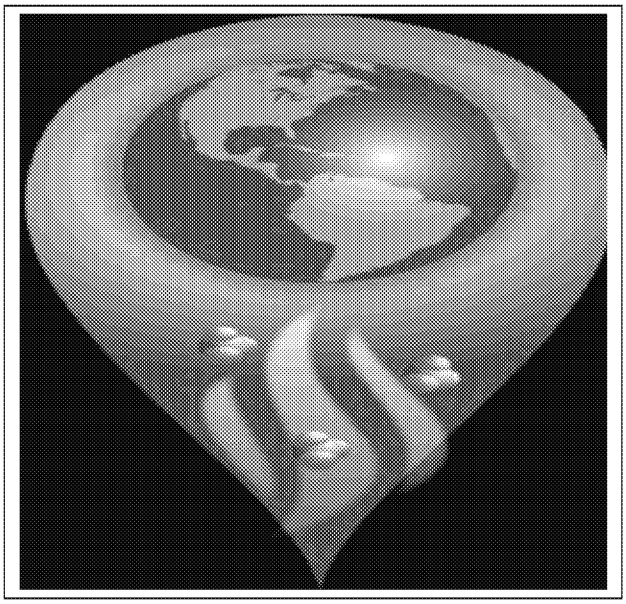
Technical/Regulatory Guidance

Draft
Evaluation of Innovative Methane Detection Technologies

Appendices



January 2018

Prepared by
The Interstate Technology & Regulatory Council
Evaluation of Innovative Methane Detection Technologies Team
In Partnership with DOE-ARPA-E

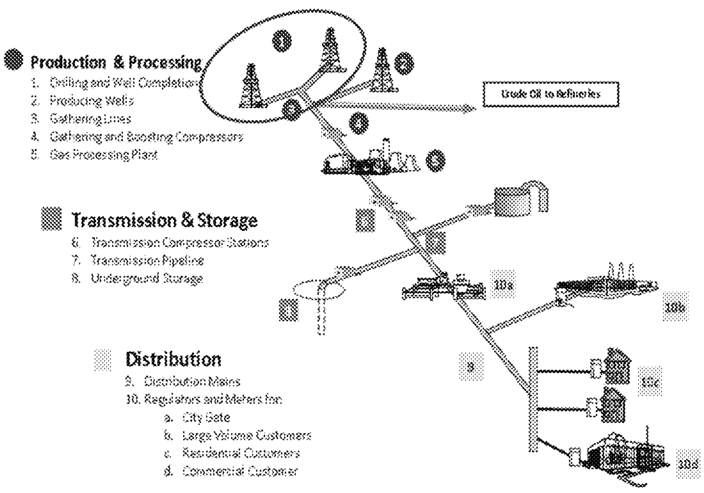
APPENDIX A CASE STUDY SUMMARIES

APPENDIX B CHARACTERIZATION ADDITIONAL MATERIAL

Additional O&G production characterization details and emission data

Field Production

Drilling



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure [SEQ Figure * ARABIC]. Oil and Gas Production – Drilling

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Table [SEQ Table * ARABIC]. Oil and Gas Production - Drilling

Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)		Field Production				Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Source (GHG Inventory)		Petroleum Systems (Annex 3.5)				
Stage (GHG Inventory)		Production Field Operations			Crude Oil Transportation	Refining
Petroleum Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Crude Oil to Refineries (not addressed here)	
Segment (GHGRP-Subpart W)		Onshore Production		Onshore Gathering & Boosting		

1.1.1.1 Drilling stage

Table [SEQ Table * ARABIC]. 2015 Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3.5, Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems

Segment/ Source	**Activity Data**- Table 3.5-5: Activity Data for Petroleum System Sources, for2015	**Average CH4 Emission Factors**- Table 3.5-3: Average CH4 Emission Factors (kg/unit activity) for Petroleum Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.5-2: CH4 Emissions (kt) for Petroleum Systems, by Segment and Source, for 2015
Well Drilling	17774 No. of oil wells drilled	0 kg/well	0

Table XX: 2015 Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3.5, Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems [1]

Sources For Leaks		
Sealing Element	**"Kick"**	**Mud/Gas Separator**

When drilling, wellheads are designed with a sealing element around the drill pipe to prevent the escape of drilling mud and potentially entrained gas present in the mud and drill cuttings brought to the surface. Wireline wellheads are sealed as well to prevent the escape of brine or other fluid under pressure and potentially gas that migrates into such fluids from the formation. In general, onshore operators in the United States practice overbalanced drilling. This technique uses mud or other fluid pressures above that of the formation pressures to keep formation fluids and gases (where present) from migrating into the wellbore and coming to the surface. There are instances where gas or fluids do escape into the wellbore (referred to as a "kick") that are metered carefully through a mud/gas separator prior to the mud being recirculated back into the well for continued operations. A "kick" is an atypical event and can result in a much more serious well control incident if not properly managed. The gas released from the mud / gas separator is typically either vented to atmosphere or flared. Such events vary in the volume of methane emitted to atmosphere, and in general have been considered more of a safety concern than an environmental issue.

1.1.1.2 Drill Rig

Sources For Leaks		
Supply Lines	**Gauges**	**Connectors**

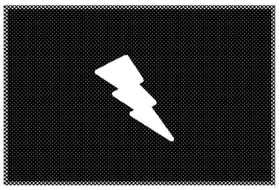
One aspect of the oil production cycle where emissions are not entirely captured are emissions from the drilling and completions phases of well development. New oil drilling rigs are designed to be mobile, and are routinely transported from location to location depending on the availability of work. A rig may stay in one location only long enough to drill a single well, or may be contracted to drill multiple wells on a single location. Depending on the depth of the target formation, it can take less than ten days to drill a single horizontal well with a 10,000 foot lateral (more definition).. A lateral is the portion of the downhole well that extends horizontally out from the vertical well shaft.

In order to drill wells efficiently requires electrical power. Modern horizontal drilling rigs are electrically driven, and routinely operate in areas where electricity for purchase (i.e. pole power) is unavailable. As a result, they are equipped with generator sets to provide the power necessary to operate the drilling rig and associated equipment. In addition, many states require air drilling, also known as pneumatic percussion drilling, or fresh water drilling up until the well penetrates and is cased through the deepest potable freshwater reservoir. For those areas requiring air drilling be employed, additional air compressors are required to supply sufficient volumes of high-pressure air to perform this technique. This point, referred to as the surface casing point, is the largest diameter bore and is cased (i.e. tubular metal casing is inserted into the wellbore) and cemented (using specialty-grade cements) in order to minimized the potential of impacts to potable aquifers.

The fuel for drilling rigs, including the compressors needed for air drilling and pumps to circulate drilling fluids, is primarily diesel fuel. Combustion of diesel fuel does not result in significant emissions of methane. In areas where natural gas is available in sufficient quantities, some operators have mandated that their drilling contractor either co-fire natural gas along with diesel fuel, or utilize generators capable of running solely on natural gas as fuel. Pollutant and GHG emissions from the combustion of natural gas in such generator sets are lower than when firing diesel fuel alone. In addition, limiting the amount of diesel fuel consumed has the downstream impact of requiring fewer fuel trucks to supply the rig and minimizing the risks inherent to driving. Firing natural gas may also present unique challenges for operators. Given the mobile nature of oil drilling rigs, all lines and connections are necessarily temporary in nature. As a result, it is possible to encounter methane leakage from these supply lines and associated equipment.

1.1.1.3 Generators

Sources For Leaks		
Temporary Pipe Connectors	**Regulators**	**Valves**
Flanges		**Incomplete Combustion**



Methane emission from electrical generator operation is unlikely, since such engines combust primarily diesel fuel. In instances where dual-fueling or natural gas firing is performed, methane emissions may result from temporary piping connections, regulators, valves, flanges and from incomplete fuel combustion.

1.1.1.4 Mud Tanks

Sources For Leaks		

Drilling mud is either water- or oil-based with additives employed to increase fluid density. In modern oil-based mud, the base is similar to mineral oil. Virgin base oil and drilling mud is stored in tanks prior to use. When in use, the mud is pumped into the drill string which provides fluid cooling to the drilling bit and rotational motion via a "mud motor" to turn the bit. The drilling mud also carries drill cuttings to the surface. Once to the surface, the mud and cuttings are separated as much as possible. The cleaned mud is recirculated back into the mud tanks for reuse, while the cuttings and residual mud are sent off-site for disposal.

Methane emissions from mud tanks can occur during a "kick" are expected since the mud carries the cuttings and hydrocarbons held in those cuttings to the surface. As the cuttings reach the surface, off-gassing of methane (and other air pollutants) would occur if there were to be a "kick". Methane emissions from this process do not appear to be well characterized. One study from 2009 (Emissions from oil and gas production facilities by ERC for TCEQ 582-7-84003) developed an emission factor for such emissions based on a similar study performed for offshore drilling operations.

Most operators require continuous monitoring for hydrogen sulfide (H_2S) and gaseous hydrocarbons around the mud tanks, focusing on where the cuttings are initially removed on the shakers. These areas are enclosed during winter operations since they are at times manned and sampled, and there are anecdotal reports of flash fires in these areas like that reported in West Greely, CO on May 8, 2017[2].

1.1.1.5 Wellhead

Segment/ Source	**Activity Data**- Table 3.5-5: Activity Data for Petroleum System Sources	**Average CH4 Emission Factors**- Table 3.5-3: Average CH4 Emission Factors (kg/unit activity) for Petroleum Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.5-2: CH4 Emissions (kt) for Petroleum Systems
Fugitive Emissions			
Oil Wellheads (heavy crude)	41376 No. of hvy. crude wells	0.9 kg/well	0.04
Oil Wellheads (light crude)	545520 No. of lt. crude wells	116.9 kg/well	63.8

Table XX: 2015 Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3.5, Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems[3]

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Gas Wells			
Non-associated Gas Wells (less fractured wells)	179658 wells	88.8 kg/well	16
Gas Wells with Hydraulic Fracturing	242235 wells	142.7 kg/well	34.6

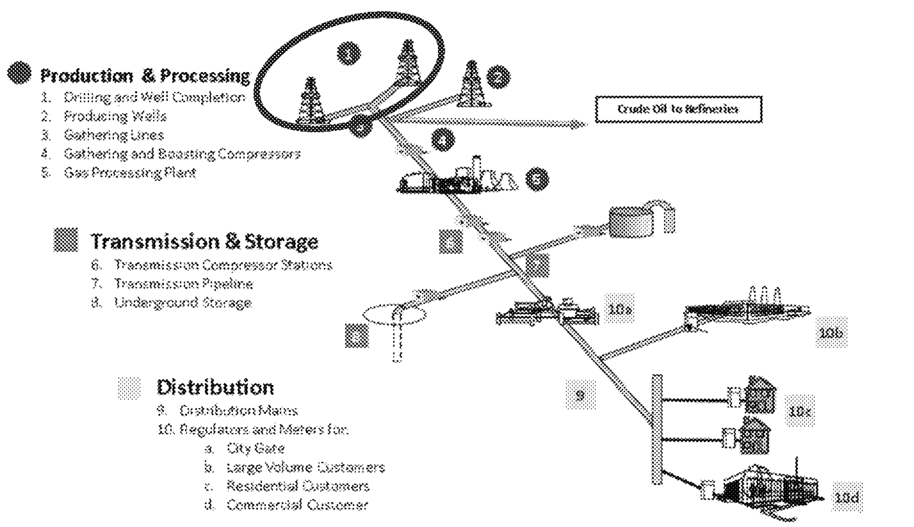
4-https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg

Table XX: 2015 Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems[4]

Sources For Leaks		
Valves	**Tubing**	**Pressure Gauges**
Sensors	**Connectors**	**Valve Packing**

The wellhead is a collection of valves and tubing that are designed to allow fluids and gases from the formation to flow up the well in a safe and controlled manner. As a collection of valves and tubing, along with pressure gauges or sensors, there is an opportunity for fugitive methane emissions from connections and valve packing. Wells may accumulate significant liquids over time that are not brought to surface which must be "unloaded" because they can affect well performance. This process is called liquids unloading. Both the fugitive emissions and emissions from liquids unloading maintenance activities are identified under the federal GHG reporting program.

1.1.2 Well completion



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Source (GHG Inventory)		Petroleum Systems (Annex 3.5)				
Stage (GHG Inventory)		Production Field Operations			Crude Oil Transportation	Refining
Petroleum Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Crude Oil to Refineries (not addressed here)	
Segment (GHGRP-Subpart W)		Onshore Production		Onshore Gathering & Boosting		

Well completion is the process of making a newly drilled well ready for production of oil and/or natural gas. This stage includes fracturing the well, the use of green completion components, flaring and the use of condensate/produced water tanks.

Segment/ Source	**Activity Data**- Table 3.5-5: Activity Data for Petroleum System Sources, for2015	**Average CH4 Emission Factors**- Table 3.5-3: Average CH4 Emission Factors (kg/unit activity) for Petroleum Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.5-2: CH4 Emissions (kt) for Petroleum Systems
Vented Emissions			
Well Completion Venting (less HF Completions)	4227 Oil well completions	14.1 kg/event	0.1
Well Workovers	44017 Oil well workovers	1.8 kg/event	0.1
HF Well Completions, Uncontrolled	10719 HF oil well completions	6763.1 kg/event	72.5
HF Well Completions, Controlled	807 HF oil well completions	338.2 kg/event	0.3

Table XX: 2015 Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3.5, Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems [5]

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Drilling, Well Completion, and Well Workover			
Gas Well Completions without Hydraulic Fracturing	762 completions/year	14.9 kg/completion	0.01
Gas Well Workovers without Hydraulic Fracturing	7815 workovers/year	50.6 kg/workover	0.4
Hydraulic Fracturing Completions and Workovers that vent	139 completions and workovers/year	36824.7 kg/(compl. & workover)	5.1
Flared Hydraulic Fracturing Completions and Workovers	341 completions and workovers/year	4906.8 kg/(compl. & workover)	1.7
Hydraulic Fracturing Completions and Workovers with RECs	3323 completions and workovers/year	3241.5 kg/(compl. & workover)	10.8
Hydraulic Fracturing Completions and Workovers with RECs that flare	1847 completions and workovers/year	4876.9 kg/(compl. & workover)	9
Well Drilling	18837 wells	52.1 kg/well	1

Table XX: 2015 Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [6]

1.1.2.1 Green completion equipment

Sources For Leaks		
Connectors	**Hammer Unions**	**Choke Manifold**
Separator	**Temporary Piping Connector**	**Pressure Regulation**
"Gas Buster" Tank		**Blow Down**

After a well completion or workover, the formation and well bore is cleaned of fracture fluid and debris. Conventionally, this debris and fluid is collected into open pits or tanks and the gas entrapped in the fluid and cuttings is vented or flared. Green completions are methods used to lower these methane losses during well completions and workovers. When using green completion equipment gas and hydrocarbon liquids are physically separated (separated from other fluids and cuttings) and captured.

Green completion equipment is generally comprised of a choke manifold, separator, temporary piping connections and other pressure regulating equipment. Such connections are made up using hammer unions, and are pressure tested for significant leakage (and other performance issues) prior to use. These connections are anticipated to leak to some degree and it is unclear if the emission factors utilized to estimate methane emissions for production are suitable for quantifying emissions from completions equipment. In addition, completion equipment can include a "gas buster" tank that allows the operator to blown down equipment if they experience sand buildup or other operational issues. When equipment is blown down to the "gas buster" any natural gas entrained in the flowback fluid is released to the atmosphere

1.1.2.2 Flare

Sources For Leaks		
Malfunction	**Connectors**	**Pressure Gauges**

Flares are used to dispose of gas released during completion or production. Flares have an open flame, and generally equipped with a pilot flame fueled using LPG or an electronic ignitor. Flares come in a variety of heights and configurations, and can be used on high and low pressure gas streams. Depending on the waste stream being combusted, gas volume and velocity, and other constituents of the gas may have widely varying destruction efficiencies.

Flare emissions are typically a function of the destruction efficiency, so if a flare is 98% efficient, then 2% of the waste stream is released uncombusted. In addition, malfunctions of the pilot flame or electronic ignition system can result in uncontrolled vented emissions of gas to the atmosphere. In addition, flares utilized during completion operations can be mobile, and as such are connected to completion equipment using temporary piping. See "Green completions equipment", above) for a description of potential fugitive methane sources

1.1.2.3 Condensate and produced water tanks

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Condensate Tank Vents			
Large Tanks w/Flares	125605169 bbl	0.01 kg/bbl	0.7

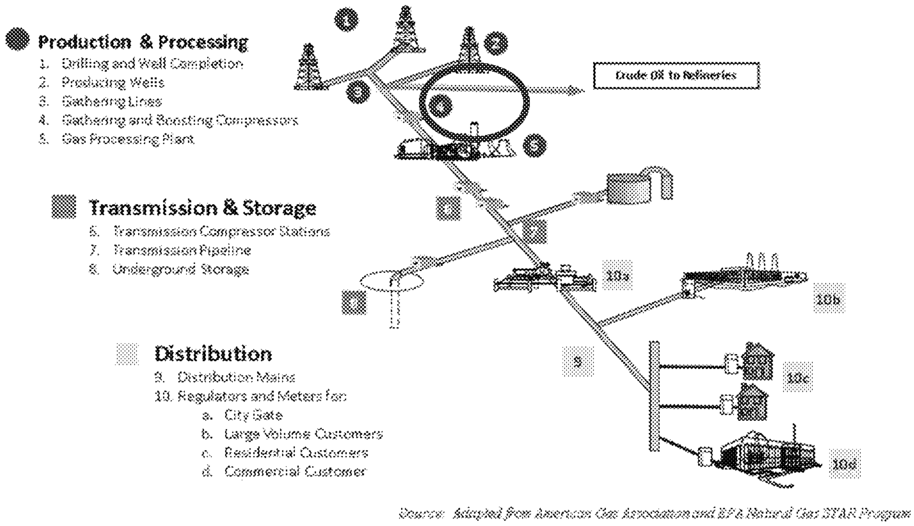
Large Tanks w/VRU	24309731 bbl	0.004 kg/bbl	0.1
Large Tanks w/o Control	31995435 bbl	0.2 kg/bbl	5.4
Small Tanks w/Flares	18065193 bbl	0.01 kg/bbl	0.1
Small Tanks w/o Flares	35911041 bbl	0.5 kg/bbl	17.2
Malfunctioning Separator Dump Valves	181910334 bbl	0.0003 kg/bbl	0.1

Table XX: 2015 Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [7]

Sources For Leaks		
Flashing	**Working**	**Breathing**

Condensate and produced water tanks used in the oil and natural gas production sector are shop fabricated and transported to site for installation. Both the federal greenhouse gas reporting program and new source performance standards include methods for quantification of methane emissions from such tanks. Briefly, emissions result from three overall processes: flash, working, and breathing. Flash emissions are evolved when a pressurized fluid stream flows into an atmospheric tank. The resulting change in pressure releases gasses, including methane, previously held in solution. Working losses result from tank fluid level changes that push vapors trapped in the tank head space to escape to the atmosphere or to an emission collection system. Breathing losses occur as the ambient temperature changes and fluids in the tank expand, which can push vapors trapped in the tank head space to escape to the atmosphere or to an emission collection system.

1.1.3



Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

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Source (GHG Inventory)	Petroleum Systems (Annex 3.5)					
Stage (GHG Inventory)	Production Field Operations				Crude Oil Transportation	Refining
Petroleum Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Crude Oil to Refineries (not addressed here)	
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		

1.1.3.1 Oil Production Field Production

Of the four sectors of natural gas systems (production, processing, transmission/storage, and distribution), production accounted for 62 ± % of emissions in 2014 according to the EPA GHG Inventory.[1] A study by Allen et al.[2] found that 61% of production emissions were from pneumatic controllers and 30% was from equipment leaks. It should be noted that the EPA inventory considers gathering and boosting within the production sector whereas in this ITRC report, production is considered part of the transmission sector.

Production emissions are broken down as those from the following six activities: flowback, pumps, pneumatic controllers, equipment leaks, liquid unloading, and workovers. A discussion of the life cycle of production emissions including drilling, fracturing and well completion, and production will follow.

1.1.3.2 Natural Gas Production from Oil Wells

All production activities the general public sees begin with the drilling of the well to access an oil-producing geologic formation. Historically, oil well production was limited to vertical wells and initially to relatively shallow depth. Fracturing of productive strata has also been employed for many years. Recent technological advances first seen only on offshore drilling rigs, like directional drilling, have been adopted by onshore operators. That innovation, coupled with advanced well stimulation (or completion) techniques like hydraulic fracturing has enabled onshore oil producers (Exploration and Production or E&P companies) to access formations that were previously inaccessible, considered uneconomic using prior drilling technology, or both. These advancements in technology have resulted in a significant shift in the economy of the United States, moving in the course of a decade from a state of relative resource scarcity to becoming one of the largest producers of natural gas worldwide. This change presents both opportunities and challenges. One of these challenges is how best to control emissions while utilizing this new energy economy. Emissions of methane from oil production contribute to this issue of climate change, and as a consequence have been the subject of regulation at the state and federal level.

The federal greenhouse gas (GHG) reporting program established in 40 Code of Federal Regulations Part 98, Subpart W is focused on capturing GHG emissions data (specifically including methane) from oil and natural gas production. It captures a number of known sources of direct and indirect methane emissions, which are listed in the subpart.

1.1.3.3 Natural Gas Field Production

Table A-134, from the EPA Greenhouse Gas Inventory 2014, lists many emissions activities for gas and condensate production operations and for midstream operations.

In alignment with the EPA GHG Inventory, onshore production operations will include:

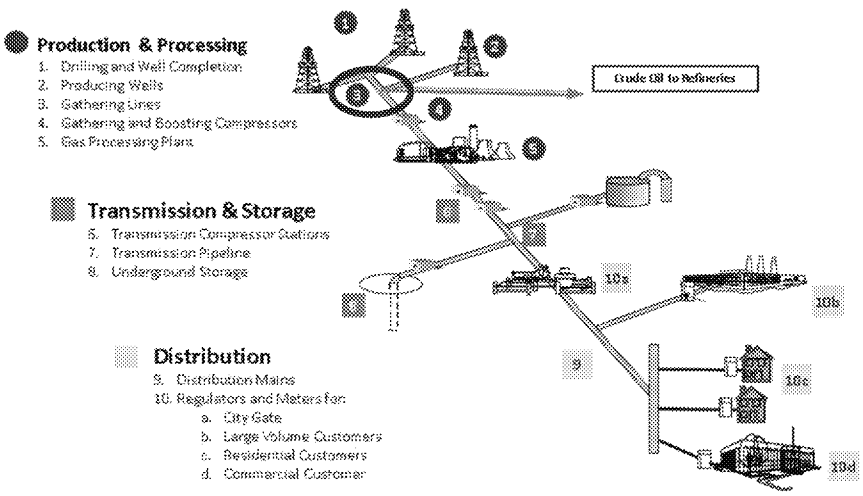
- Gas Wells
- Well Pad Equipment
- Drilling
- Well Completion and Well Workover
- Normal Operations
- Condensate Tank Vents
- Compressor Exhaust Vented
- Well Cleanups
- Blowdowns (except pipeline blowdowns which are part of midstream)
- Upsets
- Produced Water from CBM Wells

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Gas Wells			
Non-associated Gas Wells (less fractured wells)	179658 wells	88.8 kg/well	16
Gas Wells with Hydraulic Fracturing	242235 wells	142.7 kg/well	34.6
Well Pad Equipment			
Heaters	87087 heaters	249.3 kg/heater	21.7
Separators	289046 separators	404.8 kg/separator	117
Dehydrators	11235 dehydrators	486.9 kg/dehydrator	5.5

Meters/Piping	361753 meters	211.6 kg/meter	76.6
Compressors	33026 compressors	2002.5 kg/compressor	66.1

Table XX: 2015 Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems [8]

1.1.4 Gathering lines



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
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Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Midstream operations will include:

- Gathering and Boosting Compressor Stations
- Pipeline Leaks

- Pipeline Blowdowns

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Gathering and Boosting			
Gathering and Boosting Stations	5276 stations	373048.7 kg/station	1,968.20
Pipeline Leaks	408465 miles	395.5 kg/mile	161.6
Blowdowns			
Pipeline Blowdown	2190825 miles	2 kg/mile	4.3

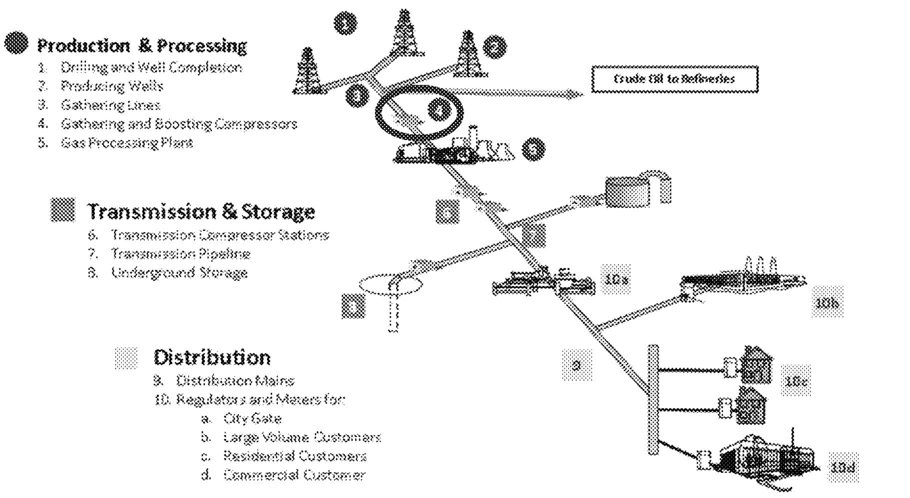
Table XX: 2015 Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [9]

Gathering pipelines transport natural gas from well pads to processing plants or transmission pipelines. The EPA U.S Greenhouse Gas Inventory estimates that there are approximately 420,000 miles of gathering pipelines in the country. Gathering lines are associated with small, aboveground auxiliary equipment such as pipeline interconnects and pigging stations. Gathering stations are larger associated facilities where gas is compressed and occasionally treated to remove liquids or acid gases. Gathering station emissions are well characterized, but very little data exist on emissions from gathering pipelines or small auxiliary equipment. There are two recent studies that have assessed emissions from gathering pipelines but have not been published yet. A study by the National Energy Technology Laboratory used a utility terrain vehicle equipped with a methane sensor to detect methane emissions along 138 miles of gathering pipeline right of way in Pennsylvania. Preliminary results indicate that only one leak was detected during the survey, a blowdown valve associated with aboveground equipment. As part of the Research Partnership to Secure Energy for America (RPSEA) Fayetteville Shale Campaign, 60 miles of gathering pipelines and 95 auxiliary equipment locations were screened with a vehicle-mounted leak detection system. Pipeline leaks were quantified with a flux chamber. Aboveground leaks were identified with OGI and then quantified with a high-flow dilution sampler. For aboveground pigging stations, 75% of locations had detected emissions with an aggregate total of 0.7 kg/hr CH4. For aboveground block valves, 44-percent of sites had detected emissions with an aggregate total of 0.1 kg/hr CH4. For both pigging stations and block valves, the top 5-percent of locations accounted for 50-percent of total emissions. Only a single pipeline leak was detected, but its emissions rate of 4 kg/hr CH4 exceeded the total of all aboveground leaks. Although these initial studies suggest that gathering pipeline emissions are small, their very small coverage (<0.05%) of total pipeline miles and finding of highly skewed emission rates indicates that more work is needed to accurately assess emissions from this source.

[HYPERLINK "http://www.rpsea.org/media/files/files/e86f7c1a/EVNT-PR-2016-SP_In-House_Air_Emission_Research_Projects_Quality_Impacts_Shale_Development-Mundia-Howe-05-26-16_OwGkPGu.pdf"]

[HYPERLINK "http://www.rpsea.org/media/files/files/f74d3577/EVNT-PR-2016-SP_12122-95_Methane_Emissions_Reconciliation_Facility_Level-Zimmerle-05-26-16.pdf"]

1.1.5 Gathering and boosting compressors



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1.1.5.1 Gathering and Boosting Stations

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
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Gathering and Boosting Stations	5276 stations	373048.7 kg/station	1,968.20
Pipeline Leaks	408465 miles	395.5 kg/mile	161.6

Table XX: 2015 Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [10]

Gathering stations are facilities that collect, compress, and sometimes treat natural gas from multiple wells and send the gas to processing plants or transmission pipelines.

Gathering lines are commonly smaller diameter pipelines (generally in the range of 6 to 20 inches) that move natural gas from the wellhead to a natural gas processing facility or an interconnection with a larger mainline transmission pipeline. "Gathering & boosting" compressor stations (SIC 1311) for gathering lines are often larger than transmission line compressor stations (SIC 4922) due to multiple pipelines coming into the station inlet, and in some cases, additional equipment needed to filter and remove liquids from the gas stream. Glycol dehydrators remove water, and Amine units remove CO_2 and H_2S, from the gas stream.

Midstream, gathering and boosting compressor stations receive gas from the surrounding gathering field. The gas can enter the facility at various pressures depending on the gas gathering pipeline(s) pressure(s). The gas is routed to separators (or slug catchers) to knockout heavier hydrocarbon liquids and water which are routed to either pressurized condensate stabilizers or to atmospheric storage tanks. Those liquids will ultimately be loaded onto trucks for transportation or piped offsite. The gas from the inlet separator is routed to compression.

Prior to 2016, EPA's estimate of gathering stations emissions was split into three categories (stations, small compressors, and large compressors). This was based on data from the 1990s EPA/ Gas Research Institute (GRI) study that included measurements from well pad compressors and gathering stations. Total emissions from these sources were estimated to be 226 [redacted] CH_4 in the EPA 2014 Greenhouse Gas Inventory (GHGI). The 2016 EPA GHGI replaced this estimate with a single value for gathering stations based on a study by Colorado State University (CSU) (Roscioli et al. 2016, Mitchell et al. 2016, Marchese et al. 2016). The study used the dual gas downwind tracer technique to quantify site-level methane emissions at 114 gathering stations operated by five companies in ten basins. Emission rates ranged from 0.7 to 700 kg/hr CH_4 with an average of 55 kg/hr. As a percentage of gas throughput, loss rates ranged from 0 to 70% with a weighted average of 0.2%. Emissions were highly skewed with 30% of facilities responsible for 80% of emissions. Onsite surveys with infrared camera revealed that 20% of facilities had substantial tank venting and these sites had on average four times higher emission rates than sites without substantial venting. Mitchell et al. (2016) used a Monte Carlo simulation to estimate national emissions from the Mitchell et al. (2016) data. They estimate that in 2012 there were 4,549 gathering facilities in the U.S. with total emissions of 1,697 Gg CH_4, or 0.40% of gas throughput. In the 2016 GHGI, EPA used this data to estimate gathering station emissions of 1,865 Gg CH_4, which makes gathering stations the largest single source in Petroleum and Natural Gas Systems.

Although the CSU study did not quantify component-level emissions, gathering stations likely have a similar profile as transmission compressor stations with the largest sources including compressor venting, compressor exhaust, and equipment leaks. Other sources such as storage tanks, pneumatic controllers, and blowdowns may also contribute to substantial emissions at some facilities. Ongoing research at compressor stations may provide data on component-level emissions at gathering facilities. Additionally, the EPA GHG Reporting Program (GHGRP) has been revised to require reporting of emissions and activity data by gathering and boosting facilities, which are defined at the basin-level by the rule, starting in the 2016 reporting year.

1.1.5.2 Midstream – Gathering and Boosting Compressor Stations

Compressor stations are an integral part of the natural gas pipeline network that moves natural gas from individual producing well sites to end users. As natural gas moves through a pipeline, distance, friction, and elevation differences slow the movement of the gas, and reduce pressure. Compressor stations are placed strategically within the gathering and transportation pipeline network to help maintain the pressure and flow of gas to market.[11] A simplified facility process flow diagram of an example compressor station is shown in Figure XX. Photos in Figures XX and XX indicate typical compressor station equipment.

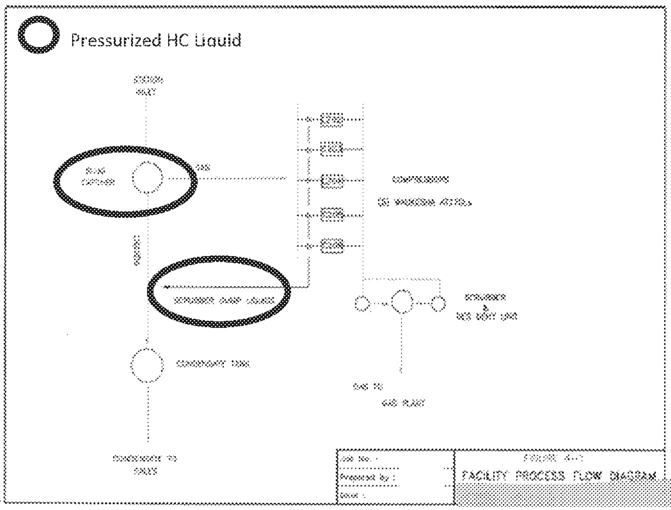


Figure XX - Compressor Station - Simplified Process Flow Diagram

Gathering lines are commonly smaller diameter pipelines (generally in the range of 6 to 20 inches) that move natural gas from the wellhead to a natural gas processing facility or an interconnection with a larger mainline transmission pipeline. "Gathering & boosting" compressor stations (SIC 1311) for gathering lines are often larger than transmission line compressor stations (SIC 4922) due to multiple pipelines coming into the station inlet, and in some cases, additional equipment needed to filter and remove liquids from the gas stream. Glycol dehydrators remove water, and Amine units remove CO_2 and H_2S, from the gas stream.

Midstream, gathering and boosting compressor stations receive gas from the surrounding gathering field. The gas can enter the facility at various pressures depending on the gas gathering pipeline(s) pressure(s). The gas is routed to separators (or slug catchers) to knockout heavier hydrocarbon liquids and water which are routed to either pressurized condensate stabilizers or to atmospheric storage tanks. Those liquids will ultimately be loaded onto trucks for transportation or piped offsite. The gas from the inlet separator is routed to compression.

Compressors can use gas or electric engines (or gas turbines – seen more often in transmission pipeline compressor stations with more steady loads) to drive the compressors that increase the gas pressure for subsequent treatment. Or, if the gas quality is adequate, direct tie-in to transmission pipelines for sales to market. Since compression raises the gas temperature, the compressed gas is cooled between stages (the larger the difference between inlet pressure and outlet pressure of the facility, the more stages of compression are needed). The inter-stage coolers typically result in some partial condensation that is removed in inter-stage scrubbers. These condensed hydrocarbon liquids, which can be at increasingly higher pressures for each stage, are routed to condensate stabilizers or atmospheric storage tanks where flash, working/standing/breathing emissions occur. Compression also includes associated equipment such as air cooler/heat exchangers (to cool the gas stream between each stage of compression), inter-stage scrubbers (to remove hydrocarbon liquids from the cooled gas stream between each stage of compression), lube oil systems, filters, coalescers, etc. Malfunctioning valves on the interstage scrubbers can allow for continuous gas seepage, or unintentional gas carrythrough which would be evident from the destination of those liquids, e.g. the storage tanks.

If water is present after compression it is removed from the gas by glycol dehydrators which can have two potential vented emissions:

- from a flash tank if present (and not routed to fuel the reboiler) and
- from the regenerator/still vent/reboiler stream

If permit or regulation requires the reduction of emissions from tanks and glycol dehydrators, then those emissions will be routed through a closed vent system to either a Vapor Recovery Unit (VRU) to be recompressed and routed to the facility inlet, or to a combustor or flare control device. The dry, compressed gas leaves the compressor station at a high enough pressure for further gas processing at a gas plant or, if the quality of the gas can meet pipeline specs, can tie directly into a transmission, mainline pipeline for sales to market. To meet transmission pipeline specs, the high pressure gas may need to be routed through a JT (Joule-Thompson) skid or dewpoint control skid where further hydrocarbon liquid dropout can occur. These high-pressure liquids can be routed to a condensate stabilizer or the atmospheric storage tanks. The higher the pressure differential, the more flash emissions will occur.

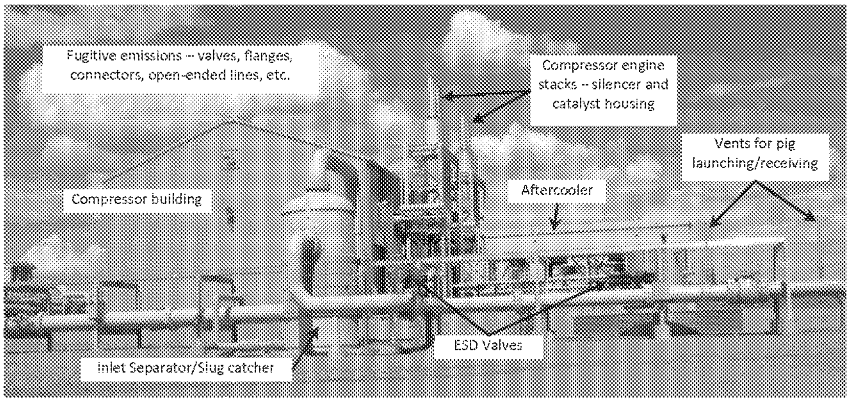


Figure [SEQ Figure * ARABIC].5 - Compressor Station - Inlet and compressor building

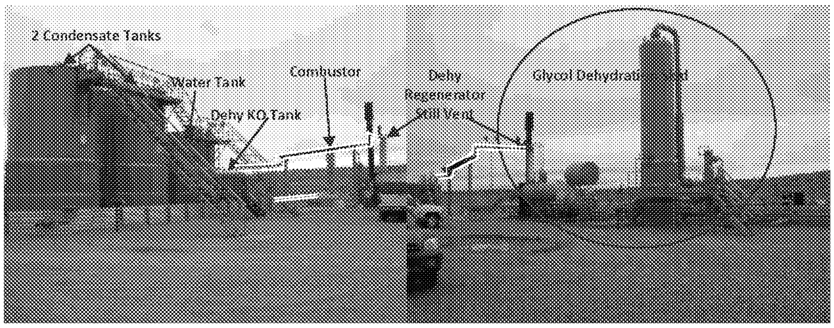


Figure 2.6 - Compressor Station - Glycol Dehydrator skid, storage tanks. Emissions from dehydrator and tanks are routed through a closed vent system (outlined in yellow) to a combustor control device

Currently in the US EPA GHG Inventory, methane emissions at Gathering & Boosting compressor stations, between the production wells and the gas processing plant, are captured in a single line item (Table A-134). Methane emission sources that could be detected include:

Intentional venting:

- Hydrocarbon liquid storage tanks, glycol dehydrator regenerators/reboilers & flash tanks, and amine units that are not required to control their emissions
- Compressor distance piece vent/drain (Figure 9)
- Compressor crankcase vent

- Compressor rod packing vent/drain
- Gas-powered pneumatic devices – controllers, chemical pumps
- Blowdown emissions to remove gas from equipment for maintenance (Figures 4 and 5)
- Emergency Shutdown (ESD) events

Unintentional:

- Fugitive emissions from valves, flanges, connectors, open-ended lines
- Hydrocarbon liquid storage tanks, glycol dehydrator regenerators/reboilers & flash tanks, and amine units that are required to control their emissions – through pressure relief devices like thief hatches, pressure relief valves (figures 6 and 7)
- Excessive distance piece venting from unintentional gas carry through
- Malfunctioning pneumatic devices
- Blowdown emissions due to improperly seated valves in blowdown piping (see Figures 4 and 5)
- ESD vent emissions due to improperly seated valves
- Unburned hydrocarbons, methane slip from any equipment that burns "waste gas" or fuel gas streams; e.g. combustors, flares, engines, turbines, reboilers, heaters, etc. (Figures 8, 10 and 11)

Every station has an emergency shutdown system (ESD) connected to a control system that can detect abnormal conditions such as an unanticipated pressure drop or natural gas leakage. These emergency systems will automatically stop the compressor units and isolate and vent compressor station gas piping (sometimes referred to as a blow down). There can be individual blowdown stacks per compressor unit or a single, central blowdown stack for the entire compressor station. Valves within the piping system linked to a blowdown stack can sometimes not close completely and so gas can seep out of blowdown stacks (see Figure 4 and 5).

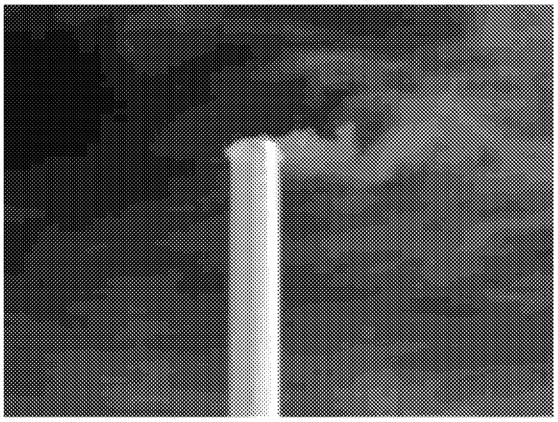


Figure 2.7- Centralized blowdown stack in a compressor station where several pieces of equipment are piped to.

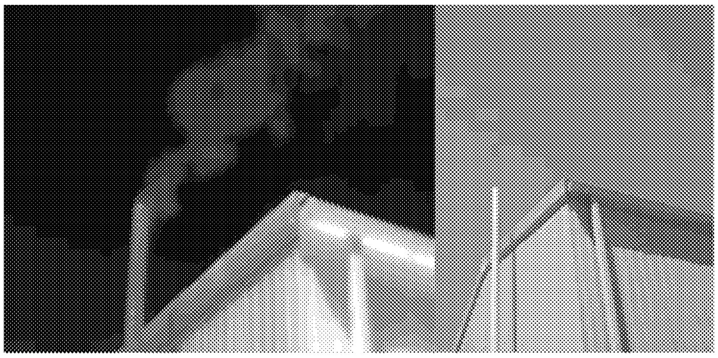


Figure 2.8 - Blowdown stack by individual compressor unit (inside building).

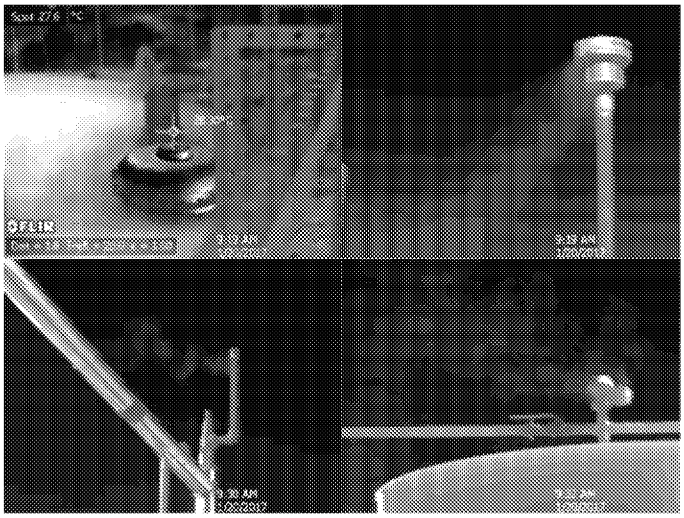


Figure 2.9- Emissions from closed vent systems used to route emissions to a control device. Top left and clockwise: thief hatch relieving pressure; spark arrestor on dehydrator knockout tank relieving pressure; pressure relief valve opened on glycol dehydrator regenerator stream; pressure relief valve venting on top of condensate storage tank.

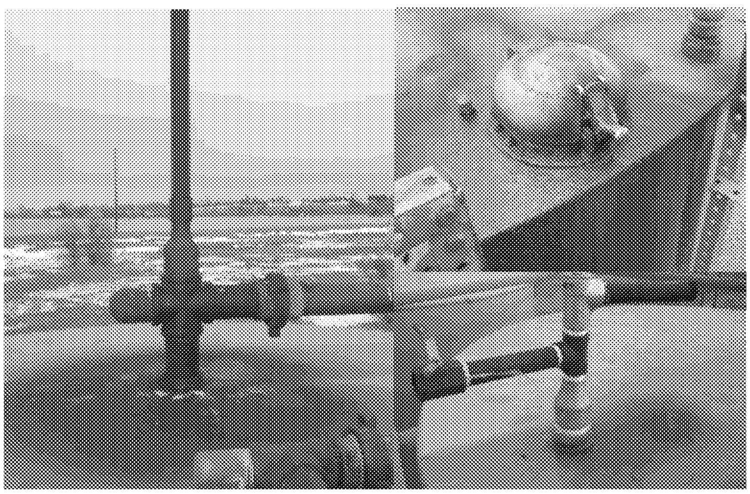


Figure 2.10 - From visual observations, examples of "burped up" oil under and around pressure relief devices (thief hatches or valves) of controlled tanks at compressor stations, indicative of over-pressure events where gas emissions would also be present.

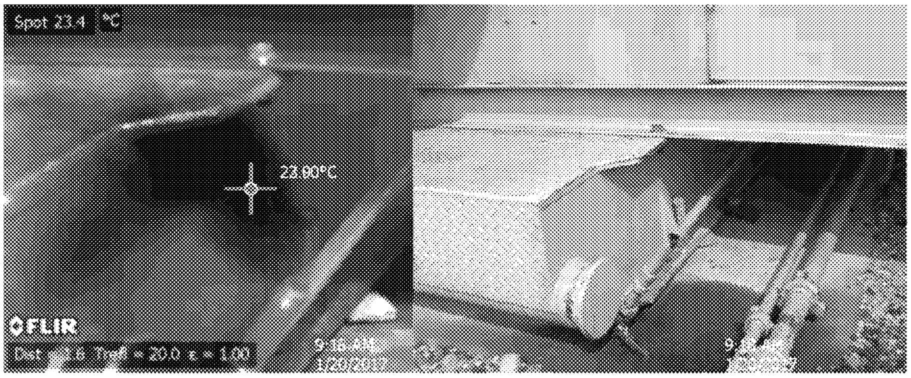


Figure 2.11 - Distance piece drain vent from single compressor. Note sprayed and pooled oil underneath vent.

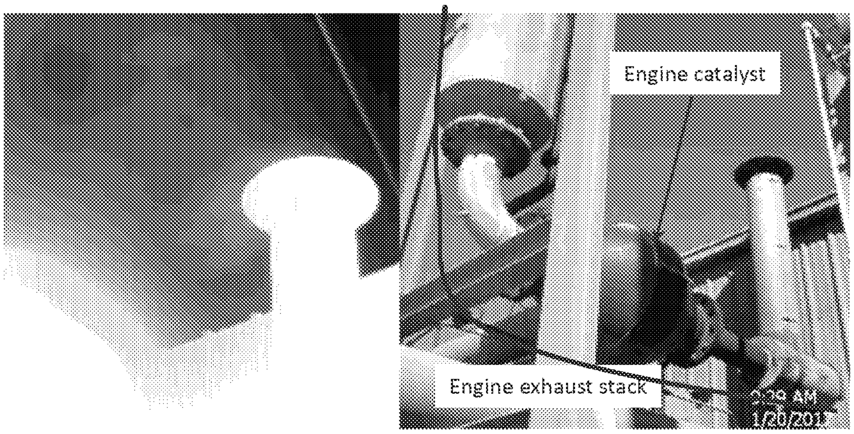


Figure 2.12 - Engine emissions escaping before the emission control catalyst.

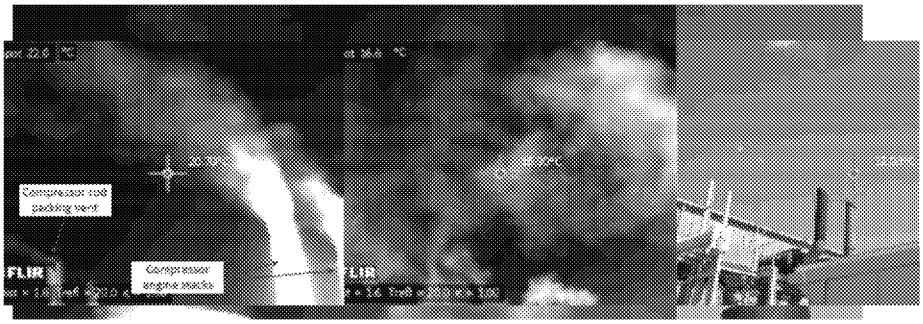
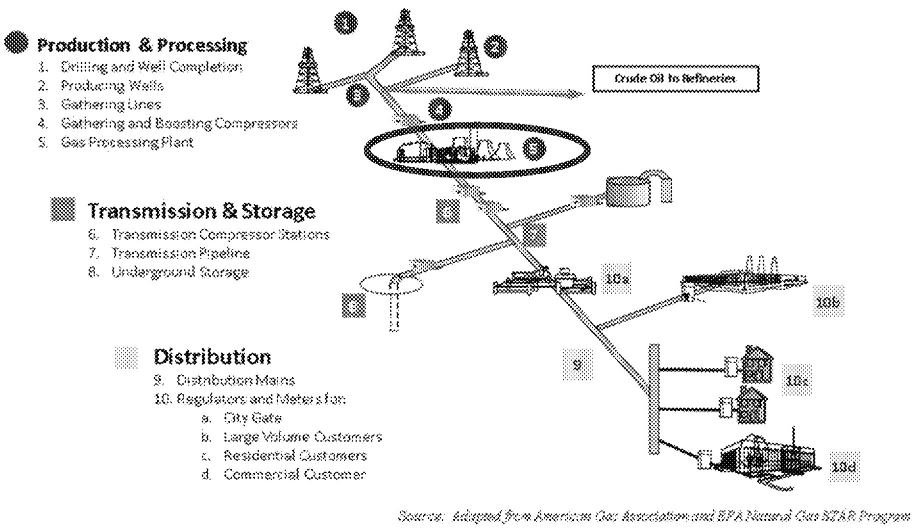


Figure XX - Unburned hydrocarbons observed from compressor engine stacks. Pan IR camera to move white hot stacks out of viewfinder to check if plume hanging together.

1.2 Processing - Gas Processing Plants



Source (GHG Inventory)	Natural Gas Systems (Annex [illegible].6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Station	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Fugitives, Vented, and Combusted			
Plant Fugitives	667 plants	24134.2 kg/plant	16.1
Reciprocating Compressors	3802 compressors	18646.9 kg/compressor	70.9
Centrifugal Compressors (wet seals)	377 compressors	56827.6 kg/compressor	21.4
Centrifugal Compressors (dry seals)	306 compressors	29985.5 kg/compressor	9.2
Dehydrators	667 plants	25335.6 kg/plant	16.9
Flares	667 plants	32634.3 kg/plant	21.8
Normal Operations			
Gas Engines	50243 MMHPhr	4622.4 kg/MMHPhr	232.2
Gas Turbines	38933 MMHPhr	109.8 kg/MMHPhr	4.3
AGR Vents	338 AGR units	42762.9 kg/AGR	14.5
Kimray Pumps	3288400 MMscf/yr	20.3 kg/MMscf	66.8
Dehydrator Vents	3690685 MMscf/yr	5.6 kg/MMscf	20.8
Pneumatic Devices	667 gas plants	3172.5 kg/plant	2.1
Routine Maintenance			
Blowdowns/ Venting	667 gas plants	53219.3 kg/plant	35.5

Table XX: 2015 Fugitive methane emissions from natural gas processing. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [12]

1.2.1 Cryogenic fractionation process

Field natural gas entering from well pads or gathering stations first enters separators (or slug catchers) to knockout heavier hydrocarbon liquids and water. By removing excess field water the separator provides operating flexibility in the case of wells sending a large volume of fluids to the facility in a relatively brief amount of time (a "slug"). This fluid, composed primarily of entrained or residual produced water and natural gas liquids (NGL), may be further separated and sent to storage in atmospheric tanks.

The incoming gas stream is further dehydrated using a dessicant system (which can be regenerated on site). Low (less than 10 ppm) moisture levels are required to avoid condensation issues in the cryogenic process.

The dehydrated gas is then sent to a turboexpander (also referred to as an expander-compressor) where the gas is compressed and then allowed to depressurize inside a temperature-controlled cryogenic tower. The depressurization of the dehydrated gas under controlled conditions results in the separation of methane (which remains gaseous at the temperature and pressure of the tower) from the remaining NGL species (ethane, propane, butane, and hydrocarbons containing five or more carbon atoms). The methane comes off the top of the tower and is sent to resid compressors (residual gas). Depending on the availability of takeaway capacity or market, some cryo plants operate in an "ethane rejection" mode, where the ethane is sent to resid compression along with methane for compression and shipment to transmission. Where available, ethane can be separated and sold as a commodity. The remaining NGL (propane, butane, and C5+) are then stored in pressurized bullet tanks as a mixed intermediate product, commonly referred to as "Y-grade". This Y-grade is the feedstock for the next processing step, fractionation. Some sites perform this processing as an integrated facility, in other cases the Y-grade is transported to the fractionation plant by truck or pipeline.

1.2.2 NGL fractionation

NGL fractionation is at base a distillation under temperature-controlled conditions. The mixed feedstock is processed through distillation towers of varying temperatures and refluxed to ensure efficient product recoveries. There are generally three commodity products produced in this operation: propane, butane, and "natural gasoline" – a mixture of C5+ hydrocarbons. Natural gasoline is typically stored in a floating-roof tank, whereas propane and butane are stored in pressurized bullet tanks. Natural gasoline can be utilized by refineries as a process material or additive, and also by the fuel ethanol industry as a denaturant. The separated products are generally shipped off-site via pipeline or rail car.

Cryogenic processing and fractionation of NGL both require very precise pressure and temperature control. Cryogenic plants have potential methane emissions from the raw gas and separated methane streams. In contrast, methane emissions from fractionation plants of any significance are unlikely. Sources of emissions are described below, and in some cases reference earlier sections of this Chapter due to similarity of operations.

1.2.3 Flares

Both cryogenic and fractionation processes are equipped with one or multiple flares to handle essentially two conditions – routine operations where relatively small volumes of gas are required to be controlled for operational or safety reasons and emergency flares, which are typically an order of magnitude larger and designed to handle a large volume of gaseous hydrocarbons in the case of a catastrophic incident. These flares are equipped with flame sensors, continuous pilot flames (and in some cases a redundant backup), and flow measuring equipment. As a result, they are less likely to operate without the presence of a pilot flame. In most respects, the general operation and control efficiency of a flare is the same as described earlier.

1.2.4 Facility blowdown

Both cryogenic and fractionation plants regularly blow down a portion of the plant for routine maintenance. Plants will also blow down to address non-routine maintenance or other operational issues. Specific to the cryogenic plant, such blowdowns have the potential to emit controlled or uncontrolled methane to the atmosphere depending on the design of the plant (whether the portion of the facility to be blown down is piped to a control device) and the volume and composition of the gas being evacuated.

1.2.5 Natural gas-fired heaters

Natural gas-fired heaters located at the facility would potentially be a source of leakage. Both cryogenic plants and fractionation plants employ thermal fluid heating systems, which require a process heater to heat that fluid. These process heaters (hot oil heaters or HOH) are typically fueled using natural gas, and as a result the piping components are subject to potential methane leakage.

1.2.6 Compressors

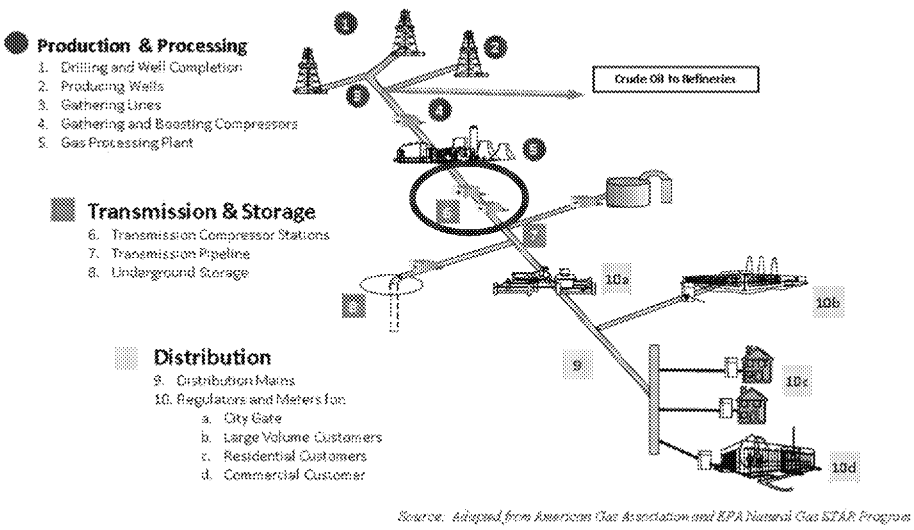
Compressors at these processing plants can be natural gas-driven or electrically driven when power is available and reliable. Employing electric drivers for such units eliminates potential emissions of methane from the fuel system, but emissions from scrubber bottles, intercoolers, and other functional components may still occur. Methane emissions from compressor operations were discussed earlier in this Chapter. Loading operations for Y-grade in cases where a compressor is employed in vapor recovery service (like truck loading of Y-grade), the pressurized portion of the collection system is subject to potential leakage. Leaking connections in the vacuum portion of the system would result in a loss of capture efficiency and increase in emissions of other hydrocarbon vapors. Methane would not be a component of the liquid being loaded and as a result emissions are not anticipated from this operation.

1.2.7 Tanks and vessels

Similar to discussions in prior sections of this Chapter, atmospheric tank emissions are a function of the pressure and composition of the incoming fluid stream. Atmospheric storage tanks at gas processing facilities may contain produced water or condensate. They may also be used as "slop tanks" where there is a mixture of different fluids in a single tank. Pressurized storage tanks (bullet tanks) are used to store propane and butane following fractionation. These hydrocarbons are gaseous at atmospheric pressure, and leaks from pressure vessels (like from an emergency relief valve) would not result in methane emissions.

1.3 Transmission and Storage

1.3.1 Transmission compressors



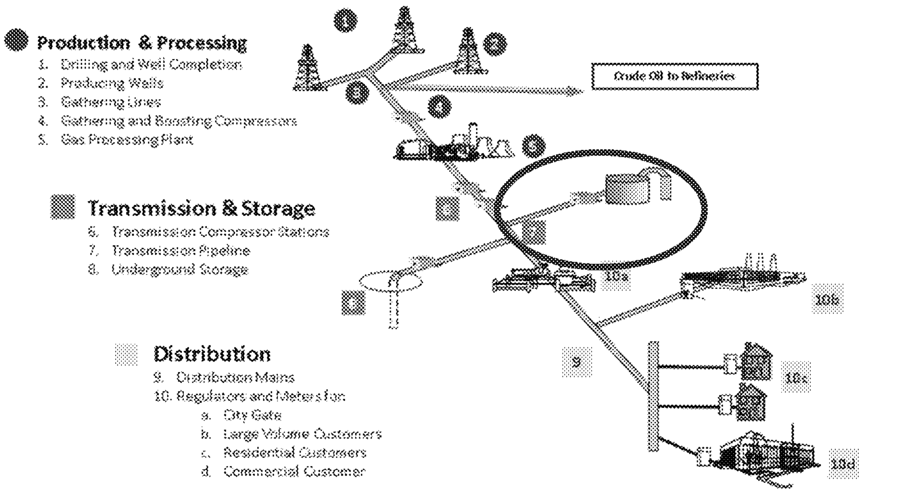
Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Compressor Stations (Transmission)			
Station Total Emissions	1834 stations	0 kg/station	572.4
Station + Compressor Fugitive Emissions	NA	63900 kg/station	117.4
Reciprocating Compressor	5221 compressors	64900 kg/compressor	339.4

Centrifugal Compressor (wet seals)	838 compressors	683031.1 kg/compressor	57
Centrifugal Compressor (dry seals)	1334 compressors	87956.2 kg/compressor	58.7
Compressor Stations (Storage)			
M&R (Trans. Co. Interconnect)	2682 stations	28007.1 kg/station	75.1
M&R (Farm Taps + Direct Sales)	79516 stations	219.3 kg/station	17.4
Normal Operation			
Dehydrator vents (Transmission)	1169007 MMscf/yr	1.8 kg/MMscf	2.1
Dehydrator vents (Storage)	1965859 MMscf/yr	2.3 kg/MMscf	4.4
Compressor Exhaust			
Engines (Transmission)	54509 MMHPhr	4622.4 kg/MMHPhr	252
Turbines (Transmission)	13006 MMHPhr	109.8 kg/MMHPhr	1.4
Engines (Storage)	4838 MMHPhr	4622.4 kg/MMHPhr	22.4
Turbines (Storage)	1699 MMHPhr	109.8 kg/MMHPhr	0.2
Generators (Engines)	2667 MMHPhr	4622.4 kg/MMHPhr	12.3
Generators (Turbines)	31 MMHPhr	109.8 kg/MMHPhr	0.003
Pneumatic Devices Trans + Stor			
Pneumatic Devices Transmission	47069 devices	628.4 kg/controller	29.6
(High Bleed)	5220 devices	2802.7 kg/controller	14.6
(Intermittent Bleed)	38217 devices	370 kg/controller	14.1
(Low Bleed)	3633 devices	221.9 kg/controller	0.8
Pneumatic Devices Storage	23093 devices	972.6 kg/controller	22.5
(High Bleed)	6870 devices	2359.2 kg/controller	16.2
(Intermittent Bleed)	14076 devices	415.2 kg/controller	5.8
(Low Bleed)	2147 devices	190.6 kg/controller	0.4
Station Venting Trans + Storage			
Station Venting Transmission	1834 compressor stations	83954.3 kg/station	154
Station Venting Storage	349 compressor stations	83954.3 kg/station	29.3

Table XX: 2015 Fugitive methane emissions from natural gas transmission. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [13]

1.3.2 Transmission pipelines



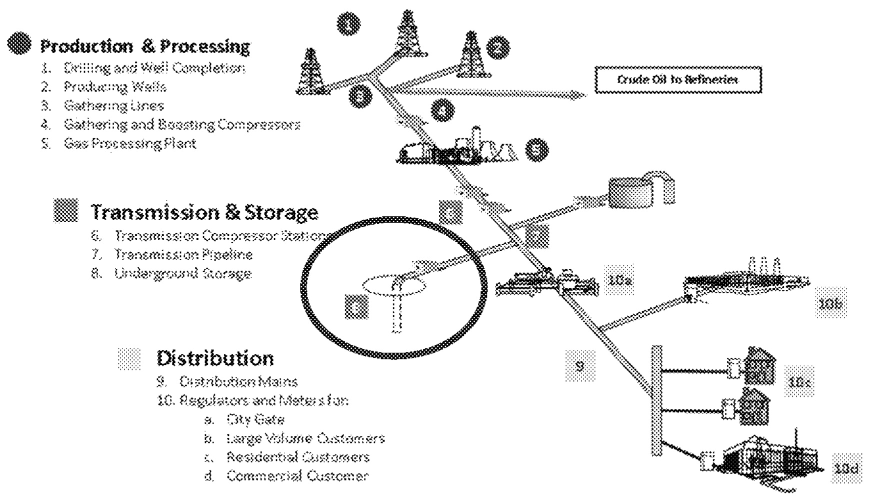
Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing		Transmission & Storage		Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Fugitives			
Pipeline Leaks	301257 miles	1122.7 kg/mile	3.3
Routine Maintenance/Upsets			
Pipeline venting	301257 miles	609.6 kg/mile	183.6

Table XX: 2015 Fugitive methane emissions from natural gas transmission. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [14]

1.3.3 Underground storage



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Fugitives			
Pipeline Leaks	301257 miles	1122.7 kg/mile	3.3
Wells (Storage)	17692 wells	5233.5 kg/well	92.6
Routine Maintenance/Upsets			
Pipeline venting	301257 miles	609.6 kg/mile	183.6

Station venting Trans + Storage			
Station Venting Storage	349 compressor stations	83954.3 kg/station	29.3

Table XX: 2015 Fugitive methane emissions from natural gas storage. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems [15]

Storage of natural gas may use underground formations such as salt caverns, mines, aquifers, depleted reservoirs and hard-rock caverns[16]. These formations may extend a few hundred to several thousand feet below the surface. Wells connect the storage reservoir to the surface wellhead assembly through a system of valves and pipes.

The wells are constructed with a larger diameter casing around a smaller diameter pipe. The casing sections, also known as joints, are 30-40 feet long and typically screw together with engineered connection collars. The collars include thread compound to assist in sealing each joint. New storage wells contain a minimum of two casings, a surface casing and a production casing[17]. Often, owners will also cement between the two casings.

There are many components which go into underground storage which may contribute to leaking including:

- Conductor casing
- Surface casing
- Intermediate casing
- Production casing
- Production tubing

The mechanism for leaks are breaches in the seals of one of the above components. API found that the three primary leak mechanisms are[18]:

1) wellhead component or seal failure;

2) production casing leak; or

3) a downhole annular barrier breach (i.e. cement sheath)

These primary leak paths are depicted in Figure xx (NEED PERMISSIONS) and described more fully below:

BELOW IS VERBATIM FROM THE API REPORT – NEED TO SUMMARIZE[19]

1) Wellhead component or seal failure

This leak path occurs when the primary and secondary seals in the wellhead fail, allowing gas in the production casing to migrate past the seals into the production casing annulus. Leaks can also occur as a result of mechanical failure of other wellhead components such as casing slips, which can allow the production casing to drop free of the wellhead seal assembly. Observations that indicate a potential leak may exist include an increase in annular pressure or flow, dependent on the annular valve position during normal well operation mode.

For a release to occur, an initial failure takes place allowing pressurized storage gas to leave the production casing. Gas then either exits through an open annular valve or pressures up the annulus, if closed. To eliminate this type of release to the atmosphere, some operators close the annular valve while the well is in operational mode. However, if pressurized gas is trapped in the annulus and not allowed to dissipate, there is a possibility of additional secondary failures that will lead to more complex, and difficult to control, release paths, hence other operators leave the annular valves open in normal operational mode.

Diagnosing the failure mechanism requires the operator to perform one or more of the following operations; test wellhead seals, observe wellhead components for indications of leakage (noise and/or hydrate deposition), and/or perform interference testing between the production casing and production casing annulus to determine if the leak is at the surface or downhole. Leak resolution may include replacing the wellhead assembly or wellhead seals and/or repair or partial replacement of the production casing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

2) Production casing leak

This leak path occurs when the production casing wall is breached. Causes include but are not limited to production casing failure due to reduced casing wall thickness from corrosion and/or the introduction of higher pressures than containable for stimulation treatments, or production casing wall collapse from outside forces such as earth movement or foreign production operations.

Observations that indicate a potential leak may exist are lower than expected shut-in pressures or gas exiting somewhere outside of the structure of the wellbore.

The stored gas can escape outside the structure of the storage wellbore from deep underground and migrate through a path of least resistance upward until it reaches an alternative escape path. The escape path could be through an oil and gas, water, or abandoned well completed in a shallower permeable formation or the path could be all the way to an escape at the surface. Operators must understand subsurface geologic conditions to assess the risk of geologic migration.

Diagnosing the failure mechanism requires the operator to perform one or more of the following operations: obtain electric logs (pipe inspection, caliper, gamma ray-neutron, differential temperature, noise, spinner flow survey, etc.); install a bridge plug and pressure test the casing.

Options for the operator to resolve the breach may include partially replacing the production casing, installing a casing internal patch, cladding, or liner, and/or remedial cementing.

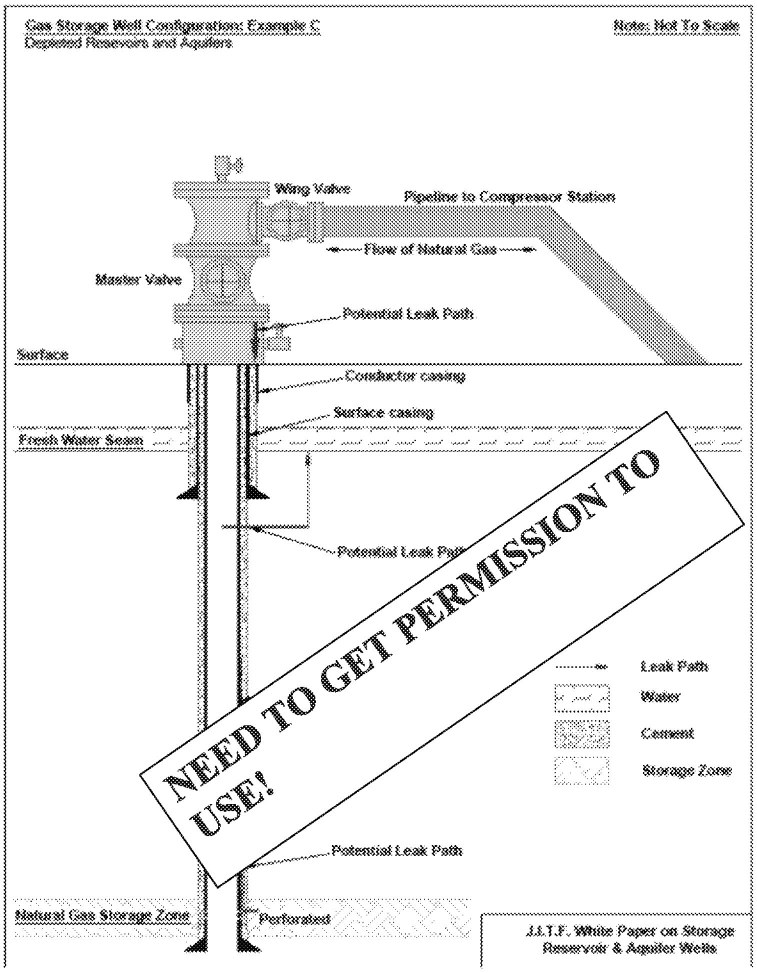
Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

3) Downhole annular barrier breach

This leak path occurs when gas and/or hydrostatic pressure in the annulus exceeds the strength of the rock below the intermediate or surface casing shoe, resulting in establishment of an escape path outside the wellbore. Observations that a potential leak may exist are gas exiting somewhere beyond the structure of the wellbore.

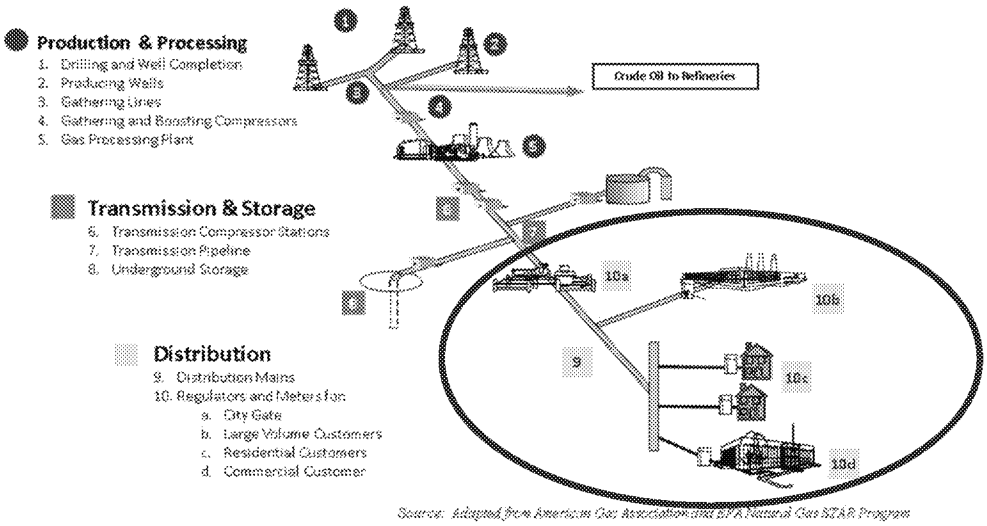
In this case storage gas finds a path of least resistance around the intermediate casing shoe and then into the subsurface lithology where it could enter an oil and gas, water, or abandoned well completed in a shallower permeable formation, or migrate all the way to an escape at the surface.

Diagnosing the failure mechanism requires the operator to obtain electric logs (gamma ray-neutron, differential temperature, ultrasonic/noise, etc.) as needed to determine the direct cause. In order to resolve this breach, the operators will usually require remedial cementing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.



1.4 Distribution

1.4.1 Distribution Mains/Services



Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

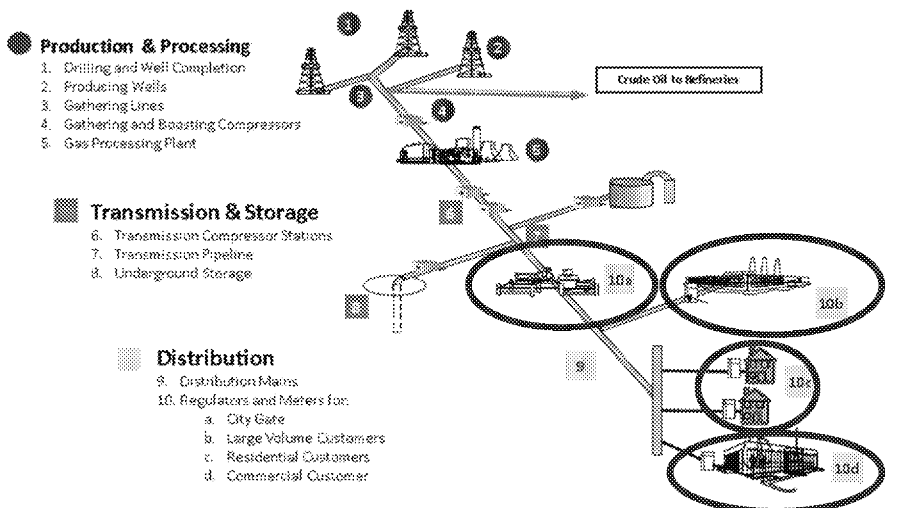
1.4.1.1 Distribution

Distribution accounted for 6% of total emissions from all sources in the US in 2014 according to the 2016 EPA GHG Inventory.[1] Emissions are separated into those from transmission-distribution transfer stations (TDTS), metering/regulating stations, distribution mains, and services. Emissions from different types of mains are discussed including unprotected steel, protected steel, plastic, and cast iron. Also, we discuss three categories of end-user emissions including industrial, commercial, and residential. We include electricity production in industrial end-use for the distribution system.

[1] EPA U.S. GHG Inventory 2016

[2] Allen, et al. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States", PNAS 110, 2013

1.4.2 Regulators and meters



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Source (GHG Inventory)	Natural Gas Systems (Annex 3.6)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Stations	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (GHGRP-Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Segment/ Source	**Activity Data**- Table 3.6-7: Activity Data for Natural Gas System Sources	**Average CH4 Emission Factors**- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	**CH4 Emissions (kt/yr)**- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Pipeline Leaks			

Mains - Cast Iron	27770 miles	1157.3 kg/mile	32.1
Mains - Unprotected steel	55863 miles	861.3 kg/mile	48.1
Mains - Protected steel	484749 miles	96.7 kg/mile	46.9
Mains - Plastic	706594 miles	28.8 kg/mile	20.4
Services - Unprotected steel	3297457 services	14.5 kg/service	47.8
Services Protected steel	14330139 services	1.3 kg/service	18.6
Services - Plastic	47517936 services	0.3 kg/service	12.5
Services - Copper	895398 services	4.9 kg/service	4.4
Meter/Regulator (City Gates)			
M&R >300	4026 stations	2142.7 kg/station	8.6
M&R 100-300	14692 stations	995.4 kg/station	14.6
M&R <100	7853 stations	727.2 kg/station	5.7
Reg >300	4402 stations	868.9 kg/station	3.8
R-Vault >300	4328 stations	50.6 kg/station	0.2
Reg 100-300	13316 stations	143.4 kg/station	1.9
R-Vault 100-300	12060 stations	50.6 kg/station	0.6
Reg 40-100	39958 stations	163.7 kg/station	6.5
R-Vault 40-100	8144 stations	50.6 kg/station	0.4
Reg <40	16943 stations	22.4 kg/station	0.4
Customer Meters			
Residential	53339363 outdoor meters	1.5 kg/meter	79.4
Commercial/Industry	5611121 meters	9.7 kg/meter	54.6
Routine Maintenance			
Pressure Relief Valve Releases	1274976 mile main	1 kg/mile	1.2
Pipeline Blowdown	2190825 miles	2 kg/mile	4.3
Upsets			
Mishaps (Dig-ins)	2190825 miles	30.6 kg/mile	67.1

Table XX: 2015 Fugitive methane emissions from natural gas distribution. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [20]

1.5 Other

1.5.1 Abandoned Wells

Abandoned oil and gas wells are inactive wells that have been decommissioned due to economic reasons such as declining production. Many states require operators to plug the well bore of abandoned wells with cement to prevent fluid migration, but numerous wells remain unplugged because they were abandoned before regulatory requirements or orphaned by defunct operators. The number of abandoned wells is highly uncertain because of poor recordkeeping during early O&G development. Brandt et al. (2013) reports a range of one to three million abandoned wells in the United States. In Pennsylvania, where wells were first drilled in the late 19th century, Kang et al. (2016) estimates there are 450,000 – 700,000 abandoned wells in the state. Several recent studies have measured methane emissions from both plugged and unplugged abandoned wells. Kang et al. (2014) directly measured emissions from 19 abandoned wells in Pennsylvania with a mean emission rate of 11 g CH_4 h^{-1} $well^{-1}$. In a follow-up study of 88 Pennsylvania wells, Kang et al. (2016) reports that high emitting wells typically are unplugged gas wells or plugged wells in coal areas that vent coal seam gas for safety reasons. Additionally, high emitting wells were found to sustain their emission rates over two years of repeat measurements. Townsend-Small et al. (2016) measured emissions at 138 abandoned wells in the Denver-Julesburg (CO), Powder River (WY), Uintah (UT), and Appalachian (OH) basins. The mean emission rate was 1.4 g CH_4 h^{-1} well- but individual rates were highly skewed: 93.5% of wells had non-detectable emission rates and the highest emitting well (146 g CH_4 h^{-1}) was responsible for over three-quarters of measured emissions. Plugging appeared to be highly effective at reducing emissions with only 1 of 119 plugged wells having detectable emissions (mean = 0.002 g CH4 h-1) compared to 8 of 9 unplugged wells (mean = 10 g CH4 h-1). Stable isotope measurements indicate that the source of emitted methane includes coal seams in addition to the targeted natural gas formation. [PLACEHOLDER – PEKNEY ET AL (IN REVIEW)].

Although methane emissions from abandoned wells usually are much lower than active wells, the large number of abandoned wells could lead to substantial emissions. Townsend-Small et al. (2016) estimate abandoned wells contribute 1.9 – 4.3% of O&G methane emissions; for Pennsylvania, they may be responsible for 5 – 8% of anthropogenic methane emissions (Kang et al. 2016). EPA does not currently include estimates of abandoned well emissions in the U.S. Greenhouse Gas Inventory, but they have requested feedback on activity data and emissions data that could be used to estimate emissions from this source in future inventories.

1.5.2 Non-Normal Distribution of Emissions: Super Emitters

A large and growing set of ~~data~~studies across the oil and gas supply chain shows that ~~extremely high emitters are underrepresented in official greenhouse gas inventories~~in any given source category, a small number of sources contribute a majority of the emissions. As a result, it has been argued that the official inventories described previously may underestimate the total volume of methane being emitted, and central estimates of emission rates (i.e. emission factors) may not capture the impact of the "fat tail" of skewed emissions distributions. However, more recently, a ground breaking study in the Fayetteville Basin showed that at least in that basin, the higher atmospheric emissions measured at mid-day by aircraft reflected the timing of higher emissions from manual liquids unloadings taking place at the time of the overflights. (Schweitzke 2018).

~~Extremely~~Unusually high emitters, commonly called "super-emitters", are infrequent. However, the impact of these few super-emitters on total emissions volume is disproportionately large. Across a variety of processes, operators, and regions, a small percentage of sites has been shown to account for a majority of emissions.

~~Official inventories have been shown to substantially underestimate total emissions, as e~~Emissions inventories are developed through extrapolating measurements made directly at emission sources to larger populations. The difficulty with this approach is obtaining a representative sample; extreme values can strongly influence average emissions, and very large statistically valid sample sizes are required to ensure these high emitters are sufficiently characterized. Table 1 below summarizes studies that discuss the discrepancies between atmospheric (top-down) measurements of methane emissions and bottom-up measurements; the former are typically much larger than the latter.~~, implying that actual emissions are likely much higher than bottom-up inventories.~~

Over time, increasing amounts of data have been collected that cumulatively get closer to a representative sample of emissions. Direct measurement studies that have found a small percentage of leaks accounting for a majority of emissions are described in Table 2 below. Scientists have found these heavy-tailed distributions across different geographies, operators, and processes. One recent paper (Brandt 2016) attempts to synthesize all prior existing direct measurements of methane leaks (including but not limited to the studies cited in the table below) to characterize the distribution more accurately. Brandt finds that heavy-tailed distributions are a pervasive characteristic of natural gas leak distributions, that the largest 5% of leaks are responsible for over 50% of the leaked methane from a given source category, and that lognormal distributions, which have sometimes been used to model heavy-tailed emission sources, still systematically underestimate the importance of the largest emitters.

Top-Down vs. Bottom-Up Measurement Studies (Table 1)

Citation	Result

Miller, S. (2013). Anthropogenic emissions of methane in the United States. PNAS, 110 (50), 20018-20022. doi: 10.1073/pnas.1314392110	Regional methane emissions due to fossil fuel extraction and processing could be 4.9 ± 2.6 times larger than in EDGAR
Brandt, A. (2014). Methane leaks from North American natural gas systems. Science, 343 (6172), 733-735. doi: 10.1126/science.1247045	National emission inventory underestimates methane emissions by 14 Tg/yr (0.73 trillion cubic feet of methane, with a range of 7–21 Tg/yr)
Zavala-Araiza, D. (2015). Reconciling divergent estimates of oil and gas methane emissions. PNAS, 112 (51), 15597-15602. doi: 10.1073/pnas.1522126112	Measured oil and gas methane emissions are 90% larger than estimates based on the US Environmental Protection Agency's Greenhouse Gas Inventory and correspond to 1.5% of natural gas production.

Super-Emitter Studies (Table 2)

Citation	Segment	Sample Size	Result
Brandt, A. (2016). Methane leaks from natural gas systems follow extreme distributions. Environ. Sci. Technol., 50 (22), 12512–12520. doi: 10.1021/acs.est.6b04303	All	15,000 previous measurements	Aggregated 15,000 measurements from 18 prior studies, finding that 5% of leaks contribute over 50% of total leakage volume.
Frankenberg, C. (2016). Airborne methane remote measurements reveal heavytail flux distribution in Four Corners region. PNAS, 113 (35), 9734–9739. doi: 10.1073/pnas.1605617113.	Gas Producing Wells, Gas Processing Plants, Gas Gathering Lines, Gas Transmission Pipelines	250 point sources	10% of emitters accounted for ~50% of observed point source emissions, roughly ~25% of total basin emissions.
Lyon, D. (2016). Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites. Environ. Sci. Technol., 50 (9), 4877–4886. doi: 10.1021/acs.est.6b00705	Oil and Gas Producing Wells	8,000 well pads	Of 8,000 well pads, 4% of sites had high-emitting sources (detection threshold was 1-3 g/s).
Hendrick, M. (2016). Fugitive methane emissions from leak-prone natural gas distribution infrastructure in urban environments. Environmental Pollution, 213, 710-716. doi: 10.1016/j.envpol.2016.01.094	Distribution Mains	100 natural gas leaks from cast iron distribution main	7% of leaks contributed 50% of emissions measured.
Omara, M. (2016). Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin. Environ. Sci. Technol., 50 (4), 2099-2107. doi: 10.1021/acs.est.5b05503	Gas Producing Wells	35 well pads	Of 13 unconventional routinely operating well pads, 23% of sites accounted for ~85% of emissions; of 17 conventional well pads, 17% of sites accounted for ~50% of emissions.
Zavala-Araiza, D. (2015). Reconciling Divergent Estimates of Oil & Gas Methane Emissions. PNAS, 112 (51), 15597–15602. doi: 10.1073/pnas.1522126112	Gas Producing Wells, Gas Processing Plants, Gas Transmission Compressor Stations	413 sites	2% of facilities are responsible for 50% of the emissions, 10% of facilities are responsible for 90% of the emissions.
Zimmerle, D. (2015). Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environ. Sci. Technol., 49 (15), 9374–9383. doi: 10.1021/acs.est.5b01669	Gas Transmission Compressor Stations, Gas Underground Storage	new measurements from 677 facilities, activity data from 922 facilities	Authors note that "equipment-level emissions data are highly skewed"

Lamb, B. (2015). Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Environ. Sci. Technol., 49 (8), 5161–5169. doi: 10.1021/es505116p	Distribution Mains/Services, Regulators & Meters	257 pipe leakage measurements, 693 metering and regulator measurements	3 large leaks accounted for 50% of total measured emissions from pipeline leaks
Rella, C. (2015). Measuring emissions from oil and natural gas producing well pads in the Barnett Shale region using the novel mobile flux plane technique. Environ. Sci. Technol., 49 (7), 4742– 4748. doi: 10.1021/acs.est.5b00099	Oil and Gas Producing Wells	182 well pads	~6% of sites accounted for 50% of emissions, 22% of sites accounted for 80% of emissions
Yacovitch, T. (2015). Mobile Laboratory Observations of Methane Emissions in the Barnett Shale Region. Environ. Sci. Technol., 49 (13), 7889-7895. doi: 10.1021/es506352j	Oil and Gas Producing Wells, Gas Gathering & Boosting Compressor Stations, Gas Transmission Compressor Stations, Gas Processing Plants	188 emission measurements	7.5% of emitters contributed to 60% of emissions
Mitchell, A. (2015). Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results. Environ. Sci. Technol., 49 (5), 3219–3227. doi: 10.1021/es5052809	Gas Gathering & Boosting Compressors, Gas Processing Plants	114 gathering facilities, 16 processing plants	Of 114 compressor stations, 30% of sites were responsible for ~80% of emissions; of 16 gas processing plants, 45% of sites were responsible for ~80% of emissions.
Subramanian, R. (2015). Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol. Environ. Sci. Technol., 49 (5), 3252–3261. doi: 10.1021/es5060258	Gas Transmission Compressor Stations	47 compressor stations	Of 45 compressor stations, 10% of sites accounted for ~50% of emissions.
Kang, M. (2014). Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania. PNAS, 111 (51), 18173–18177. doi: 10.1073/pnas.1408315111	Abandoned Wells	19 abandoned wells	Of 19 abandoned wells, 3 had flow rates 3x larger than the median flow rate.
Allen, D. (2014). Methane Emissions from Process Equipment at Natural Gas Production Sites: Pneumatic Controllers. Environ. Sci. Technol., 49 (1), 633-640. doi: 10.1021/es5040156	Gas Producing Wells	377 pneumatic controllers	20% of devices accounted for 96% of emissions.
Allen, D. (2014). Methane Emissions from Process Equipment at Natural Gas Production Sites: Liquids Unloadings. Environ. Sci. Technol., 49 (1), 641-658. doi: 10.1021/es5040156r	Gas Producing Wells	107 wells with liquids unloading	Without plunger lift, 20% of wells accounted for 83% of emissions; with plunger lift and manual, 20% of wells accounted for 65% of emissions; with plunger lift and automatic, 20% of wells accounted for 72% of emissions.

1.5.3 Offshore Facilities

Segment/ Source	Activity Data- Table 3.6-7: Activity Data for Natural Gas System Sources	Average CH4 Emission Factors- Table 3.6-2: Average CH4 Emission Factors (kg/ unit activity) for Natural Gas Systems and Sources	CH4 Emissions (kt/yr)- Table 3.6-1: CH4 Emissions (kt) for Natural Gas Systems, by Segment and Source
Vented Emissions			
OCS Offshore Platforms, Shallow water oil,	1447 No. of shallow water oil platforms	116358.9 kg/platform	168.3

fugitive vented, and combusted			
OCS Offshore Platforms, Deep water oil, fugitive, vented, and combusted	29 No. of deepwater oil platforms	659657.7 kg/platform	19.3

Table XX: 2015 Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3.6, Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems [21]

While this effort does not include offshore facilities within its scope, there is need for further analysis and research into the offshore subsector. There are programs and resources currently available to begin this effort, for example the Gulf Offshore Activity Data System program (GOADS) is a study conducted by the Bureau of Ocean Energy Management Enforcement (BOEM). This study is set up to comply with 30 CFR 550.302-304 which requires that petroleum and natural gas production platforms located in the Federal Gulf of Mexico to report their activities to BOEM once every three to four years. The activities reported include:

Emissions sources

Volumes of throughputs from some equipment

Fuel consumption by combustion devices

Parametric data from some emission sources like glycol dehydrators

While this requirement does not apply to all U.S. offshore oil and natural gas operation, it may be assessed and evaluated for strengths and opportunities. This ITRC team recommends that a future project include offshore oil and gas operations equipment inventory and emissions analysis.

APPENDIX C REGULATIONS ADDITIONAL MATERIAL

C.1. United States – Federal Fugitive Methane Emission Regulations

C.1.1 Environmental Protection Agency

New Source Performance Standards (NSPS) for the Oil and Natural Gas Sector Subpart OOOOa [Citation: Federal Register Vol. 81, No. 107, 6/3/16. 35824-35942]

EPA's NSPS Subpart OOOOa ("NSPS OOOOa"), which is a revision to NSPS OOOO, became effective on August 2, 2016 and applies to facilities in the drilling, production and processing segments of the onshore oil and gas sector that commenced construction, modification or reconstruction after September 18, 2015. As of the publication of this document, the status of NSPA OOOOa, particularly in regard to the leak detection and repair (LDAR) requirements for fugitive emissions, is uncertain. However, a summary of the LDAR requirements as they currently stand will be provided.

NSPA OOOOa regulates methane and VOCs from a variety of sources, including fugitive emissions. NSPA OOOOa also includes a provision for approval of emerging or alternative technologies for fugitive emissions detection. The summary below provides an overview of the fugitive emissions/LDAR and emerging technology sections of the rule.

NSPS Subpart OOOOa Requirements for Fugitive Emissions Footnote here Fed Reg

NSPS OOOOa imposes standards to control GHGs (in the form of limitations on methane emissions) and VOC emissions from fugitive emission components at well sites (including centralized tank batteries) and compressor stations (gathering & boosting as well as transmission & storage). Semiannual or quarterly monitoring and repair of equipment and components that may leak or release fugitive emissions at these facilities is required.

Leak monitoring must be conducted using optical gas imaging (OGI), which is often referred to as an infrared (IR) camera, and repairs must be made if any emissions are seen or observed. EPA determined OGI, which can see emissions not visible to the naked eye, to be what is known as the Best System of Emissions Reduction (BSER) for fugitive emissions from well sites and compressor stations, which means OGI meets the standard of performance established by EPA for achieving the necessary emission reductions at these facilities. However, OOOOa also allows that Method 21 (M21), which detects leaks and indicates their size as a concentration level in air in parts per million (ppm), may be used as an alternative monitoring method to OGI, which can only detect emissions. If M21 is used, then component repair must be conducted if the leak concentration level is 500 ppm or greater. Repairs must be made within 30 days of finding fugitive emissions and a resurvey of the repaired component must be made within 30 days of the repair using OGI or M21 at a repair threshold of 500 ppm. Monitoring and repair records must be maintained and submitted with semi-annual reports to EPA or the delegated authority.

If OGI is used, a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company-defined area must be developed and implemented. Owners and operators develop a plan that describes the facilities subject to monitoring in that area, including descriptions of equipment, plans for how monitoring will be conducted, etc., that apply to all similar facilities. This allows owners and operators to develop a monitoring plan for groups of similar facilities within an area for ease of implementation and compliance. These plans must include a typical "observation path" that is focused on the field of view of the OGI instrument being used (not the physical location of the OGI operator) to ensure all components get monitored, as well as the maximum viewing distance. The intent is to allow for the use of all types of OGI instruments (e.g., mounted, handheld or remote controlled) for monitoring. The observation path description may be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI instrument's monitoring path.

Provision for Emerging Technology

Fugitive emissions monitoring and repair is a work practice standard, as allowed under the Clean Air Act (CAA). A work practice standard is an emission limitation (BSER) that is not necessarily in a numeric format, such as the visualization of fugitive emissions using OGI. The Clean Air Act also allows approval of an alternative means of emission limitation (AMEL) for a work practice standard if it can be proven that an equal reduction in emissions will be achieved through that alternative *(42 C.F.R. §7411(h)(3))*. To that end, and because methane and VOC leak detection technology has been undergoing continuous and rapid development and innovation, potentially yielding, for example, continuous emissions monitoring technologies, NSPS OOOOa includes a process for EPA to permit the use of an innovative technology for reducing fugitive emissions at well sites and/or compressor stations *(40 C.F.R. §60.5398a)*.

Specifically, owners or operators may submit a request to the EPA for an "alternative means of emission limitation" where a technology has been demonstrated to achieve a reduction in emissions at least equivalent to the reductions achieved under the OGI work practice of NSPS OOOOa.

To facilitate the application and review process, NSPS OOOOa identifies information that must be included in the AMEL application in order for EPA to evaluate the emerging technology, which includes:

- a description of the emerging technology and the associated monitoring instrument or measurement technology;
- a description of the method and data quality used to ensure the effectiveness of the technology;
- a description of the method detection limit of the technology and the action level at which fugitive emissions would be detected;
- a description of the quality assurance and control measures employed by the technology;
- field data (covering a period of at least 12 months and contemporaneously conducting M21 or OGI leak detection at prescribed frequency) that verify the feasibility and detection capabilities of the technology; and
- any restrictions for using the technology.

This process allows for the approval and use of any work practice developed in the future that can demonstrate methane and VOC emission reductions at levels that are at least equivalent to the reductions achieved when using OGI or M21 for fugitive emissions monitoring. This process also allows for the use of alternative fugitive emissions mitigations approaches utilizing periodic, continuous, fixed, and mobile (including aerial), or hybrid monitoring approaches.

Consistent with the AMEL provision of the CAA, any application will be publicly noticed in the Federal Register, including all required information for evaluation. The EPA will provide an opportunity for public hearing and comment on the application and on intended action the EPA might take. The EPA then makes a final determination on the AMEL application within six months after the close of the public comment period and publishes its determination in the Federal Register. If the final determination is denial of the application, the EPA will provide reasoning for denial and recommendations for further development and evaluation of the emerging technology, if appropriate. If an AMEL is granted approval, then it is specific to a single facility and applicant.

Note that in order for a technology to be considered for AMEL under OOOOa it must be capable of detecting methane and VOCs, or be able to demonstrate equivalent reductions of methane and VOCs if not all compounds can be detected.

As of the date of this document, EPA had not received any AMEL applications under OOOOa.

Citation: Federal Register Vol. 81, No. 107, 6/3/16. 35824-35942 [cite again here? – how much of the text above is directly copies and needing a citation?]

C.1.2 Greenhouse Gas Mandatory Reporting Rule

The Greenhouse Gas Mandatory Reporting Rule (also known as the Greenhouse Gas Reporting Program or GHGRP) was published by EPA in October 2009 and went into effect in January 2010. The rule requires annual reporting of greenhouse gases (GHG), including methane, from large emission sources across a range of industrial categories, including the oil and gas sector. The purpose of the rule, as noted by EPA *([* HYPERLINK "https://www.epa.gov/sites/production/files/2014-09/documents/ghgrp-overview-factsheet.pdf" *])*, is to provide for a "collection of comprehensive, nationwide emissions data [that] is intended to provide a better understanding of the sources of GHGs and to guide development of policies and programs to reduce emissions." Thus, unlike NSPS OOOOa, actual emission reductions are not required under GHGRP, only calculation and reporting of emissions. Additionally, VOCs are not covered under GHGRP since they are not GHGs.

One of the options in GHGRP for estimating emissions from equipment leaks ("fugitive emissions") in the oil and gas sector is an equipment leak survey. Equipment leak surveys are required for certain component types, and reporters must use one of the monitoring methods specified in the rule to conduct those surveys. In recent revisions to the rule, effective January 1, 2017 *(reference here)*, new monitoring methods for detecting leaks from equipment in the petroleum and natural gas source category were added to be consistent with the leak detection methods in the New Source Performance Standards (NSPS) for the oil and gas industry. These revisions were the result of a review of existing requirements in the GHGRP to address potential gaps in coverage and to improve monitoring methods to ensure high quality data reporting. EPA also received direction to explore potential regulatory opportunities for applying remote sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions in the oil and gas sector.

Subpart W of the GHGRP specifies the monitoring methods that may be used for equipment leak surveys, which include Optical Gas Imaging, Method 21, Infrared Laser Illuminated Instruments and Acoustic Leak Detection Devices. The rule specifies how leaks are to be measured for each monitoring method used. Additionally, Subpart W allows for temporary use of alternative monitoring methods not specified in the rule for certain facilities and operations.

C.1.3 Alternative Work Practice (AWP) to Method 21 for Leak Detection and Repair

Numerous EPA air emissions standards, including those for segments of the oil and gas sector, require a specific work practice (NSPS VV & VVa) that identifies Method 21 for equipment leak detection and repair (LDAR) of fugitive VOC emissions. On April 6, 2006, the EPA proposed a voluntary alternative work practice (AWP) for LDAR using optical gas imaging (OGI), which was a newly developed technology at the time. The AWP was eventually finalized and adopted in 2008 and allows for the voluntary use of OGI in place of Method 21 for any rule that requires LDAR for fugitive VOCs. The AWP still requires annual monitoring using Method 21 but all other periodic monitoring may be performed with OGI.

Note that in NSPS OOOOa, OGI and/or Method 21 is the allowed work practice for LDAR at well sites and compressor stations. However, for gas processing plants subject to OOOOa, OGI is still considered the AWP for purposes of LDAR and Method 21 is the required work practice.

The AWP was the first time EPA allowed an alternative to Method 21 for LDAR and, in essence, opened the door for potential consideration of other innovative leak detection technologies or methods.

C.1.2 Bureau of Land Management (BLM)

C.1.2.1 BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation (43 CFR Parts 3100, 3160 and 3170)

The BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation rule ("Waste Prevention Rule") was proposed in 2016 and became effective on January 17, 2017. On December 7, 2017, the BLM announced a temporary suspension of the Waste Prevention Rule. The rule is now delayed until January 17, 2019, giving the BLM time to review parts of the rule. However, a summary of the requirements as they currently stand will be provided. The rule includes LDAR requirements for existing and new facilities located on BLM-managed lands, which includes semi-annual leak monitoring at well sites (including oil wells that also produce natural gas and produced water handling facilities) and quarterly monitoring at compressor stations.

<u>Alternative Technology Provisions</u>

The Waste Prevention rule applies to hydrocarbon emissions (methane + VOCs) and, similar to NSPS OOOOa, allows for the use of OGI or Method 21 for leak monitoring, as well as approved alternatives. The rule specifies that any person may request approval of an alternative monitoring device and protocol (e.g. a device that monitors continuously, but is less sensitive than optical gas imaging, might achieve results equivalent to optical gas imaging due to the gas savings from early detection) by submitting a Sundry Notice to BLM that includes the following information:

(1) Specifications of the proposed monitoring device, including a detection limit capable of supporting the desired function;
(2) The proposed monitoring protocol using the proposed monitoring device, including how results will be recorded;
(3) Records and data from laboratory and field testing, including but not limited to performance testing;

(4) A demonstration that the proposed monitoring device and protocol will achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring;
(5) Tracking and documentation procedures; and
(6) Proposed limitations on the types of sites or other conditions on deploying the device and the protocol to achieve the demonstrated results.

The BLM may approve an alternative monitoring device and associated inspection protocol if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring. The BLM will provide public notice of a submission for approval and may approve an alternative device and monitoring protocol for use in all or most applications (i.e. once approved, any operator could use it, which differs from NSPS OOOOa), or for use on a pilot or demonstration basis under specified circumstances that limit where and for how long the device may be used. The BLM will post on its web site a list of each approved alternative monitoring device and protocol, along with any limitations on its use. The BLM intends that the decision to approve the use of an alternative monitoring device would be made only at the national level, by the Director, Deputy Director, or an Assistant Director, as, once approved, the alternative monitoring device could be used at any facility subject to BLM requirements.

In addition to the alternative monitoring device option, the Waste Prevention rule also includes a provision for approval of an alternative instrument-based leak detection program. The BLM may approve an operator's request to use an alternative instrument-based leak detection program if the BLM finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring. For example, an operator might propose a program that included more frequent inspections for some sites and less frequent inspections for others, or an operator may be able to deploy an alternative leak detection device or system, approved by the BLM, on a continuous basis and achieve results that would allow for less frequent inspections using optical gas imaging or Method 21. In essence, the alternative leak detection program allows for flexibility to potentially combine use of an alternative leak detection monitoring device with an already-approved monitoring device or method under the rule (OGI and Method 21).

The operator must submit its request for an alternative leak detection program through a Sundry Notice that includes the following information:

(1) A detailed description of the alternative leak detection program, including how it will use OGI and/or Method 21, along with sensory leak detection methods (audio/visual/olfactory or AVO), and an identification of the specific instruments, methods and/or practices and elements of the approach;
(2) The proposed monitoring protocol;
(3) Records and data from laboratory and field testing, including, but not limited to, performance testing, to the extent relevant;
(4) A demonstration that the proposed alternative leak detection program will achieve equal or greater reduction of gas lost through leaks compared to OGI or Method 21 with AVO semiannual/quarterly monitoring;
(5) A detailed description of how the operator will track and document its procedures, leaks found, and leaks repaired; and
(6) Proposed limitations on types of sites or other conditions on deployment of the alternative leak detection program.

Unlike the alternative monitoring device approval, a BLM State Director could approve an alternative leak detection program if the alternative program is determined to achieve equal or greater reduction of gas lost through leaks compared to the leak detection program required under the rule. However, the rule does not allow other operators to use an alternative leak detection program requested by and approved for a specific operator, as the results may not be transferable.

The BLM may also approve an alternative leak detection program if the operator demonstrates, and the BLM agrees, that compliance would impose such costs as to cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease. The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and hydrogen sulfide content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease as part of the alternative leak detection program request.

Finally, the Waste Prevention rule also allows an operator to choose to comply with the EPA fugitive emissions monitoring requirements in NSPS OOOOa in lieu of complying with the LDAR provisions in the Waste Prevention rule for all sites and equipment not already deemed in compliance with the BLM LDAR provisions. This provision allows an operator with some facilities subject to NSPS OOOOa and the Waste Prevention rule and other facilities only subject to the Waste Prevention rule to apply a single leak detection regime to all of their facilities, rather than complying with NSPS OOOOa for some facilities and the BLM requirements for others.
If an operator decides to comply with NSPS OOOOa, they must also look for leaks on tank covers and closed vent systems (whose inspection requirements reside in a different part of OOOOa than the LDAR provisions)

As of the date of this document, the BLM State Director for New Mexico has approved the use of Tunable Diode Laser Absorption Spectroscopy (TDLAS) as part of an alternative instrument-based leak detection program

Federal Register Notice - [HYPERLINK "https://www.gpo.gov/fdsys/pkg/FR-2016-11-18/pdf/2016-27637.pdf?utm_campaign=subscription%20mailing%20list&utm_source=federalregister.gov&utm_medium=email"]

C.1.3 Pipeline and Hazardous Material Safety Administration (PHMSA) - Federal Gas Pipeline Safety Regulations

The safety of natural gas pipeline systems are regulated by the United States Department of Transportation's (USDOT) Pipeline and Hazardous Material Safety Administration (PHMSA). PHMSA directly administers the pipeline safety program and develops and enforces requirements for interstate and intrastate pipelines. These regulations are written to ensure safety in the design, construction, testing, operation, and maintenance of pipeline facilities and in the siting, construction, operation, and maintenance of liquefied natural gas (LNG) facilities. PHMSA ensures compliance with regulations through operator inspections, enforcement actions, and accident investigations.

PHMSA also administers grant-in-aid funding to States that provides reimbursement for up to 80% of qualified expenses incurred by the State program for pipeline inspection activities. Each participating State delegates responsibility for pipeline safety to a State agency. State agency duties normally consist of operator inspections, compliance and enforcement, safety programs, accident investigations, pipeline construction inspections, and record maintenance and reporting.

The State agency may adopt additional or more stringent standards for intrastate pipeline facilities provided such standards are compatible with Federal regulations [1]. Under an *agreement* or *interstate* agent agreement, the State agency assumes inspection responsibility for facilities and reports probable violations to PHMSA for compliance action.[2]

C.1.3.1 PHMSA Natural Gas Pipeline Regulations

PHMSA requires operators of pipeline facilities to follow regulations applicable to the commodity being transported. For natural gas, which is mostly methane, the requirements are found in Code of Federal Regulations 49 Part 192 (49 CFR Part 192) – Transportation of Natural and Other Gasses by Pipeline, and include leak monitoring or survey requirements, which will be discussed here.

An important aspect of the natural gas pipeline safety regulations is that for each operations and maintenance technical requirement found in Part 192, there must be a corresponding operator procedure for meeting that requirement. Operators are required to follow both the technical requirements found in Part 192 and the procedures it has developed for meeting those requirements, including leak monitoring and repair. It is also important to note that the requirements found in Part 192 are considered minimum requirements, meaning each operator can, and often does, have procedures that are more prescriptive and more stringent than the requirements found in Part 192.

<u>Operations and Maintenance</u>

Each pipeline operator is required to prepare and follow a manual of written procedures for conducting operations and maintenance activities for each pipeline, including leak monitoring and repair.

> (1) Each transmission line and distribution main must be surveyed at regular intervals for indications of leaks using leak detection equipment and hazardous leaks must be repaired promptly. A hazardous leak is a leak that represents an existing or probable hazard to persons or property and requiring prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.
> (2) Compressor stations, pressure regulating stations, and valves along pipelines also need to be tested and inspected at regular intervals to ensure that the equipment is operating as designed and able to be used when needed. These testing and inspection activities normally include leak detection and repair.

<u>Leak Detection</u>

As noted, Part 192 requires leakage surveys be conducted using "leak detector equipment", which is a performance-based requirement, meaning that any equipment capable of detecting all leaks in gas distribution or transmission systems may be used. The regulations do not mandate the use of any specific type of leak detection equipment and since natural gas is primarily methane, equipment that can only detect methane is acceptable. However, it is imperative that procedures exist for proper use and calibration of the equipment. In addition, since State pipeline safety regulations are allowed to be more specific and more stringent than federal regulations, a state may adopt leak detection equipment requirements of its own for conducting leakage surveys in its specific jurisdiction.

Another important aspect of pipeline safety related to leak surveys is integrity management (IM). Transmission and distribution operators are required to have IM programs to evaluate and address risks on their pipelines, which include using performance metrics to measure the number of hazardous leaks either eliminated or repaired, and the total number of leaks either eliminated or repaired, categorized by cause.

C.2. State Government Fugitive Emission/LDAR Regulations

In addition to federal requirements, some state governments have adopted their own fugitive emission/LDAR regulations for the oil and gas sector that supplement or go beyond federal requirements. Some of these regulations target or include methane and some do not. Additionally, some of the regulations allow for the approval of innovative or alternative leak detection technologies, while others mandate that only certain types of technologies or methods may be used. A summary of specific state fugitive emission/LDAR regulations is provided below.

ITRC conducted a survey of state and local governments concerning fugitive emission/LDAR regulations for the oil and gas sector that was coordinated by ITRC's state Point of Contacts (POCs). Information obtained through that survey helped inform what is included in this section.

C.2.1 State Government Regulations that apply to Fugitive Methane Emissions

C.2.1.1 California – Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (Air Resources Board)

California is unique among states to have the only oil and gas regulation focused exclusively on methane. California's "Greenhouse Gas Emissions Standards for Crude Oil and Natural Gas Facilities" regulation, which became effective January 1, 2017 and requires full compliance by December 31, 2018, is aimed at reducing statewide methane emissions from new and existing facilities in the oil and gas production, processing, and storage sectors, and from transmission compressor stations. Its requirements include:

- Vapor collection on uncontrolled separators and tanks;
- Leak Detection and Repair (LDAR) at facilities not already covered by local air districts' VOC rules;
- LDAR monitoring at underground gas storage facilities, as well as ambient air monitoring and daily or continuous wellhead monitoring;
- Emissions standards for both reciprocating and centrifugal compressors, in addition to LDAR; and
- No-bleed requirements for pneumatic devices and pumps.

The statewide methane regulation's LDAR provision requires quarterly inspections using detection and measurement instruments compatible with US EPA Method 21, with the final leak standard being 1,000 ppmv. Currently, there is no alternative leak detection method or technology allowed, but the California Air Resources Board (CARB), which administers the rule, may consider allowing alternative methodologies in future amendments if, for example, Optical Gas Imaging technology evolves to allow quantification in addition to detection. However, the underground gas storage provision does allow for different and more innovative instrument technologies. This provision includes daily or continuous leak monitoring at the wellheads as well as ambient air monitoring and the use of OGI in the case of a well blowout.

California has eight oil and gas producing local air districts that have their own LDAR rules -- some for decades -- to reduce VOC emissions from oil and gas operations. California used these district VOC rules as a starting point for its methane regulation's LDAR provision. For the most part, the district and CARB LDAR provisions are similar, but there are some differences. For example, inspections may be less frequent in district rules, and the leak concentration standards vary. The district LDAR rules typically exempt components at oil and gas facilities that exclusively handle gas, vapor, or liquid with a VOC content of 10 percent by weight or less. It is these components that the CARB regulation covers. District VOC rules cover about 80 percent of all the components in the sector.

C.2.1.2 California – Oil & Gas Transmission and Distribution System Requirements (California Public Utilities Commission)

On June 15, 2017, the California Public Utilities Commission (CPUC) approved the Natural Gas Leak Abatement Program establishing Best Practices (BPs) and reporting requirements for the CPUC Natural Gas Leak Abatement Program developed in consultation with California Air Resources Board (CARB) to support the goal of reducing methane emissions in the state by 40% by 2030.

The BPs include six related to leak detection including: 1) a 3 year distribution leak survey cycle, 2) special targeted leak surveys on more vulnerable pipeline types, 3) enhanced methane detection such as mobile or aerial surveys, 4) stationary methane detectors for early detection of leaks in above ground facilities, 5) frequent leak surveys, which may use EPA Method 21, optical gas imaging, or other methods, at above ground transmission and high pressure distribution facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations, as appropriate, and 6) leak quantification and geographic tracking and evaluation.

More detailed information can be found at:

[HYPERLINK "http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Risk_Assessment/Final%20Best%20Practices%20Revised%20Staff%20Recommendations%20with%20BP%20Matrix%20January2017.pdf" \t "_blank"]

C.2.2 State Government Regulations or Permits That Apply to Fugitive Methane Plus VOC Emissions

C.2.2.1 Colorado – Regulation No. 7 (Air Pollution Control Division)

In 2014 and 2017, Colorado's Air Quality Control Commission (AQCC) adopted updates to Regulation No. 7 that focus on reducing methane and VOC emissions from the upstream oil and gas sector, which includes well production facilities, natural gas compressor stations, and natural gas processing plants (https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_1.pdf).

The regulation includes LDAR provisions for well production facilities and compressor stations that require one-time or periodic monitoring for leaks from components using an Approved Instrument Monitoring Method (AIMM), which may be OGI, EPA Method 21 or other Division-approved instrument based monitoring device or program ("alternative AIMM"). An alternative AIMM must be able to demonstrate it is capable of achieving emissions reductions at least as effective as using OGI or Method 21. Section XII.L.8, which applies to the 8-hour Ozone Control Area only, specifies the information that must be provided for an alternative AIMM application, which is also identified in a guidance document developed for alternative AIMM applications by Colorado's Air Pollution Control Division (see below).

If OGI is used as AIMM, a leak is defined as any detectable emissions observed using the OGI instrument. If Method 21 is used, a leak is defined as either a hydrocarbon concentration of 2,000 ppm or 500 ppm, depending on the facility type, when it was constructed, or if it is located in the 8-hour Ozone Control Area. For an alternative AIMM, leak identification requiring repair will be established as set forth in an approval under Section XII.L.8

There are also separate requirements specific to atmospheric storage tanks that store hydrocarbon liquids, which includes condensate, oil and produced water, known as Storage Tank Emission Management (STEM). STEM requires that all storage tank hydrocarbon emissions must be routed to air pollution control equipment. To help accomplish this, a STEM plan has to be developed and implemented to identify technologies, practices and strategies to prevent the release of tank emissions to atmosphere. Additionally, periodic AIMM monitoring and audio, visual and olfactory (AVO) inspections of affected tanks must be conducted to check for the release of emissions. Any detectable tanks emissions must be addressed or repaired.

Updates to Regulation No. 7 in 2017 also require periodic AIMM inspections of gas-actuated pneumatic controllers at well production facilities and natural gas compressor stations in the 8-hour Ozone Control Area to find and address controllers in need of repair, adjustment or replacement. The expectation is that these pneumatic controller inspections will occur during the same inspections, and using the same AIMM, that are conducted for compliance with the LDAR requirements of Regulation 7. If detectable emissions from a pneumatic controller are observed, a determination must be made whether the pneumatic controller is operating properly within five (5) working days after detecting the emissions, and if the pneumatic controllers is determined to not be operating properly then specific actions must be taken to return the pneumatic controller to proper operation as defined in the rule.

Colorado's Air Pollution Control Division ("APCD") has developed guidance and an application form for technologies or methods seeking to gain approval as AIMM under Regulation No. 7 ([HYPERLINK "https://www.colorado.gov/pacific/cdphe/AIMM"]). The guidance specifies that a technology or method must not be in the prototype or development phase in order be considered and may be approved as either a quantitative or non-quantitative AIMM. A quantitative AIMM must be able to detect and measure the hydrocarbons in the emissions stream, while a non-quantitative AIMM only needs to detect the hydrocarbons in the emissions stream. The criteria used for evaluating an AIMM application include the operating requirements and limitations of the technology or method, including the emissions detection threshold and anything that impacts detectability, ability to pinpoint the specific source of emissions or leak location, calibration and maintenance requirements, data logging and recordkeeping capabilities, training or certification for use and operation, and testing results (lab and/or field), including any comparative monitoring with OGI and/or Method 21. If a technology or method is approved as AIMM, APCD issues an approval letter to the applicant that outlines the conditions or requirements for use of the AIMM and posts the approval letter on the APCD's AIMM web page. Once an AIMM is approved, it may be used by anyone to meet Regulation No. 7 requirements.

As of the date of this document, two technologies or methods had been approved as AIMM by APCD.

C.2.2.2 Pennsylvania – General Permit 5 and Permit-Exemption Category No. 38

Pennsylvania's General Permit 5 (GP-5) is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are that are classified as minor sources of air pollution.

GP-5 was first approved by the Pennsylvania Department of Environmental Protection (DEP) on February 1, 2013. ([HYPERLINK "http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf"]) An owner or operator of a facility subject to GP-5 must conduct monthly leak monitoring at the facility on a monthly basis using AVO methods and on a quarterly basis using an OGI camera or other leak detection monitoring device approved by the DEP. A leak is defined as any release of gaseous hydrocarbons detected by the OGI camera or through AVO methods.

Permit-exemption category no. 38 (PE #38) was finalized on August 10, 2013 and applies to unconventional wells, wellheads, and associated equipment and requires an LDAR program within 60 days after a well is put into production, and annually thereafter, as a condition of meeting the permit-exemption. The LDAR program must utilize an OGI camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2%, or other leak detection monitoring devices approved by the DEP. LDAR must be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquid service.

As of the date of this document, DEP has not published any guidance on the application and evaluation procedures for "other leak monitoring devices" to gain approval for use under GP-5 and PE #38. A Frequently Asked Questions (FAQ) document published by DEP for GP-5 and PE #38 states that an alternate leak detection technology could be used if "it is approved by DEP following a case-by-case evaluation of the device or technology."
(http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/gp/FAQ_GP-5_AND_EXEMPTION_CATEGORY_NO_38.pdf)

As of the date of this document, no requests for approval of alternate leak detection technologies or methods had been submitted to the DEP.

C.2.2.3 Ohio – General Permits 12.1, 12.2 and 18.1

The Ohio Environmental Protection Agency (OH EPA) approved two types of general permits for high volume horizontal hydraulic fracturing, oil and gas well site production operations (General Permits 12.1 and 12.2) in May 2014 and a general permit for equipment leaks from natural gas compressor stations (GP 18.1) in early 2017 ([HYPERLINK "http://www.epa.ohio.gov/dapc/genpermit/genpermits.aspx" \l "127854016-available-permits"])

Each of these permits require development and implementation of an LDAR program for equipment that has the potential to leak (pumps, compressors, pressure relief devices, connectors, valves, flanges, intermittent/snap-action pneumatic controller, vents, covers, any bypass in a closed vent system, and each storage vessel) using an OGI camera or EPA Method 21. Leak monitoring must be conducted within 60 or 90 days of startup and quarterly thereafter. GP 12.1 and 12.2 allow the monitoring frequency to be reduced after the first four quarters of monitoring if the leak rate of the equipment at a facility is determined to be less than 2.0%. A leak is defined as any detectable emissions with the OGI camera or concentrations between 500 – 10,000 ppm depending on the component if Method 21 is used.

C.2.3 State Government Regulations or Permits that apply to Fugitive VOC Emissions

C.2.3.1 Utah – General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery

In June 2014, the Utah Department of Environmental Quality (UTDEQ)issued "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" (https://deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf). This General Approval Order (GAO) requires LDAR for affected equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) at a well site and/or tank battery using OGI, EPA Method 21 or tunable diode laser absorption spectroscopy (TDLAS). Inspection or monitoring frequency is based on projected throughput of crude oil and condensate in the storage tank(s) on site, or annually if no storage tanks are on site. The monitoring frequency may be reduced at sites with tanks that have large throughputs if no leaks are found over a certain period.

A leak is defined as a reading of 500 ppm with a Method 21 analyzer or TDLAS, or visible/detectable emissions with OGI.

Although the GAO does not specifically indicate that it covers methane emissions, UTDEQ estimated methane reductions that would be achieved through implementation of the GAO *(ref. "Comparison of State Leak Detection and Repair Programs, 4/20/16, EC/R Inc.).*

C.2.3.2 Wyoming – Air Quality Standards & Regulations, Chapter 8

In June 2015, the Wyoming Department of Environmental Quality (WYDEQ) finalized revisions to Chapter 8 of the Wyoming Air Quality Standards and Regulations (WAQSR). The revisions include a requirement in Section 6 for multiple or single well production facilities and all compressor stations with fugitive emissions greater than or equal to 4 tons per year of VOCs in existence prior to January 1, 2014 in the Upper Green River Basin ozone nonattainment area to develop and implement an LDAR program by January 1, 2017. Operators must monitor components quarterly using EPA Method 21, an OGI/IR camera, or other instrument based technology or method, along with AVO inspections.

The rule also requires that companies submit the protocols for their LDAR program to WYDEQ for approval. Thus, if the protocol includes a request to use an alternative instrument based monitoring method or technique besides Method 21 or an OGI/IR Camera, then WYDEQ could approve that if it deemed it to be acceptable.

As of the date of this document, no company has submitted an LDAR protocol to WYDEQ requesting the use of an alternative instrument based monitoring method or technique

Wyoming regulations are available at [HYPERLINK "http://soswy.state.wy.us/Rules/RULES/9868.pdf"]

C.3. Local Government Fugitive Emission/LDAR Regulations

C.3.1 City of Thornton, Colorado

On August 22, 2017, the City Council for Thornton, CO adopted regulations for oil and gas operation within city limits. The regulations include requirements for a leak detection and repair plan to detect and promptly repair leaks in equipment and facilities. As stated in the regulations in Section 18-870(f)(19), "At a minimum, the plan shall be comparable to EPA Method 21, and provide for:

a. Monthly infrared camera and olfactory inspections of new and existing wells, related facilities, and equipment. After one year of operation, inspections shall be made at least quarterly.
b. Baseline inspections within 60 days after authorization of the oil and gas operation.
c. Computerized monitoring and leak detection with 24-hour reporting capabilities to the operator, who will then immediately provide notice to the Thornton Fire Department and emergency and safety administrator."

Details of the regulations may be found at [HYPERLINK "https://www.cityofthornton.net/government/citydevelopment/Documents/oil-gas/Finalsigned%20regulationordinance.pdf"]

The [HYPERLINK "http://www.coga.org/" \t "_blank"] (COGA) and the [HYPERLINK "http://www.api.org/" \t "_blank"]'s Colorado Petroleum Council (CPC) jointly sued the City of Thornton on October 10, 2017 over [HYPERLINK "https://www.cityofthornton.net/government/citydevelopment/Documents/oil-gas/Finalsigned%20regulationordinance.pdf" \t "_blank"].

C.4. International Methane Emission Regulations

Outside of the United States, a few other countries have adopted or are in the process of adopting regulations to reduce methane emissions from the oil and gas sector. The basis for these regulations is often to help meet commitments for greenhouse gas (GHG) reductions under international climate agreements. A summary of select countries with methane regulations or methane reduction requirements for the oil and gas industry is summarized below.

C.4.1 Canada

In Canada, federal regulations were proposed on May 27, 2017 to regulate hydrocarbon emissions from the upstream oil and gas sector. The requirements cover five main hydrocarbon (methane and VOC) emission sources, including leaks from equipment. The proposed regulations cover production sites, gas processing facilities, and transmission facilities. Operators must inspect equipment components three times per year using portable monitoring instruments or optical gas imaging instruments or an approved alternate leak detection technology. Approval for the use of the alternate technology would be granted at a facility level. Fast-tracked approvals would be possible if any other jurisdiction has approved the use of the technology. Approvals would be granted based on data collected by the operator over a 12-month period to show that the alternate leak detection technology is capable of detecting a leak of hydrocarbons that is detectable by an optical gas imaging instrument. The operator must also provide a description of the technology including detection limit, protocols for use, and repeatability. Final regulations are expected to be published in 2018.

C.4.1.1 – Canadian Provinces

There are provincial directives in place to manage fugitive emissions, particularly in British Columbia and Alberta, where the majority of on-shore oil and gas activities are occurring. Saskatchewan, a major oil and gas producing province, has a directive in place to address venting, but does not address the management of fugitive emissions. The provincial directives do not cover all sources of fugitive and venting emissions. Directives are generally considered non-binding and non-enforceable unless incorporated by reference in a regulation or permit. Permits issued by the provinces are site-specific authorizations for a specific activity or industry, and can vary in the type of sources covered and the stringency of requirements.

Regulatory measures:

Directive 084, published by the Alberta Energy Regulator (AER), and effective April 2017, requires monthly leak surveys at facilities in the Peace River area of heavy oil and bitumen production. Allowed leak survey instruments include optical gas imaging infrared cameras, organic vapor analyzers, and other techniques or equipment that provide an equivalent leak detection capability, if the equivalence has been demonstrated to AER's satisfaction.

Voluntary measures:

The Canadian Association of Petroleum Producers (CAPP), an industry association, developed the voluntary *Best Management Practice: Management of Fugitive Emissions at Upstream Oil and Gas Facilities* (BMP) in 2007 ([HYPERLINK "http://www.capp.ca/publications-and-statistics/publications/116116"]) for reducing fugitive emissions of methane and volatile organic compounds at oil and gas facilities. The BMP provides guidance for developing fugitive management programs which focus on areas most likely to offer significant cost-effective control opportunities (on specific component types and service applications). This BMP is referenced in British Columbia's Flaring and Venting Reduction Guideline and Alberta's Directive 60 which state that facilities must develop and implement a program which "meets or exceeds the CAPP *Best Management Practice for Fugitive Emissions Management*". The CAPP BMP lists a number of methods that could be used to detect, measure or estimate leaks, such as portable monitoring instruments, optical gas imaging instruments, and quantitative remote sensing techniques, and assesses qualitatively the effectiveness and approximate cost of these methods.

C.4.2 Norway

According to the Norwegian Environmental Agency, "Methane emissions are covered by Norway's GHG reduction goals. Norway plans to reduce its global greenhouse gas emissions by the equivalent of 30 % of its own 1990 emissions by 2020. By 2030, Norway plans to reduce its GHG emissions by the equivalent of 40 % compared to the 1990 emissions." ([HYPERLINK "http://www.miljodirektoratet.no/en/Areas-of-activity1/Climate/Short-Lived-Climate-Pollutants/Key-regulations-and-goals-on-SLCPs-in-Norway/"]).

Norway regulates methane emissions from the oil and gas sector through several acts or laws, including the Pollution Control Act, Greenhouse Gas Emission Trading Act, CO2 Tax Act (offshore) and the Petroleum Act.

C.4.3 Mexico

As a result of Mexico's participation in the United Nations Framework Convention on Climate Change, the state-owned oil company of Mexico, Petroléos Mexicanos (PEMEX), has taken steps to reduce methane emissions from its operations, including implementation of the Nationally Appropriate Mitigation Actions (NAMA) with the assistance of the British Embassy Prosperity Fund. The goal of NAMA is to reduce methane emissions in natural gas processing, transport, and distribution systems through periodic leak detection and repair (LDAR) activities. NAMA outlines both qualitative and quantitative methods for detecting leaks, including bubble tests, optical gas imaging (OGI), ultrasonic leak detectors, portable organic vapor analyzers, quantitative remote sensing techniques, and engineered estimates. PEMEX may also follow internationally recognized methods for leak identification, such as EPA Method 21.

C.4.4 Saudi Arabia

Saudi Arabia requires semi-annual LDAR inspections at oil and gas facilities that can be reduced to annual inspections if leaks are reduced. Facility operators must keep track of all leaks found and repaired and report them on an annual basis. Note, however, that the regulations do not outline proper leak detection methods or provide repair guidelines, therefore, operators can implement different methods and repair thresholds and timeframes.

C.4.5 Australia – New South Wales

The state of New South Wales in Australia has regulations to limit methane emission leaks from coal seam gas (CSG) operations. The regulations require CSG operators to develop and implement an LDAR program for their operations. Leak monitoring must be conducted in accordance with U.S. EPA Method 21 and U.S. EPA's Best Practices Guide for Leak Detection and Repair. (http://www.epa.nsw.gov.au/resources/epa/2564-methane-fact-sheet.pdf)

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APPENDIX E GLOSSARY

Abandoned well: A well that is no longer in use, whether dry, inoperable, or no longer productive..

Accuracy: Accuracy of an analytical measurement is how closely the result corresponds to the true value. This normally requires the use of standards in carefully calibrating the analytical methods

Action level
The generic term applied to any numerical concentration value which will be compared with environmental data to arrive at a decision or determination about a potential contaminant(s) of concern (from survey through remediation) or for a user-defined volume of media using environmental sample data.

Acreage: Land leased for oil and gas exploration and/or land for which ConocoPhillips owns the mineral rights.

Adsorption: Adsorption is the adhesion of molecules of gas, liquid, or dissolved solids to a surface. The term also refers to a method of treating wastes in which activated carbon is used to remove organic compounds from wastewater. Additionally, Adsorption is defined as the process by which nutrients such as inorganic phosphorous adhere to particles via a loose chemical bond with the surface of clay particles.

Non-covalent bonding of a chemical to a solid surface.

Annulus: The space between the casing and the wall of the borehole, between two strings of casing, or between tubing and casing.

Anticline: A convex-upward formation of rock layers, which may form a trap for hydrocarbons.

Appraisal Well: A well drilled as part of an exploration drilling program which is carried out to determine the physical extent, reserves and likely production rate of a field.

Aquifer: An underground layer of water-bearing permeable rock or unconsolidated materials (gravel, sand, silt or clay) from which groundwater can be extracted using a water well.

Azimuth: Direction a horizontal well is drilled relative to magnetic North

definition

B

Barrel (BBL): A unit of volume measurement used for petroleum and its products or water used or produced by the industry (1 barrel = 42 gallons).

Barrel of oil equivalent (BOE): A measure used to aggregate oil and gas resources or production, with one BOE being approximately equal to 6,000 cubic feet of natural gas.

BCF: One billion cubic feet of natural gas.

BSFe: One billion cubic feet of natural gas "equivalent".

Bitumen: A generic term applied to natural inflammable substances of variable color, hardness, and volatility, composed principally of a mixture of hydrocarbons substantially free from oxygenated bodies

Blow down -

Blow-out preventers (BOPs): High pressure wellhead valves designed to safely shut off the uncontrolled flow of hydrocarbons.

Blow-out: When well pressure exceeds the ability of the wellhead valves to control it.

BOED: Barrels of oil equivalent per day.

Borehole: The hole in the earth created by a drilling rig.

Brine: A salt water and chemical mix that is produced after fracturing a well with elevated Total Dissolved Solids (TDS) levels and often naturally occurring metals such as barium and strontium. Brine must be treated or disposed of as contaminated waste water.

British thermal unit (BTU): The heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Butane: Butanes are highly flammable, colorless, easily liquefied gases

C

CAPEX: Capital expenditures.

Carbon capture and storage (CCS): Process by which carbon dioxide emissions are captured and removed from the atmosphere and then stored, normally via injection into a secure underground geological formation.

Casing string: The steel tubing that lines a well after it has been drilled. It is formed from sections of steel tube welded or threaded together.

Casing: Pipe cemented in the well to seal off formation fluids or keep the borehole from caving in.

Cementing: To prepare and pump cement into place in a wellbore. Cementing operations may be undertaken to seal the annulus after a casing string has been run, to seal a lost circulation zone, to set a plug in an existing well from which to push off with directional tools or to plug a well so that it may be abandoned.

Christmas tree: The assembly of fittings and valves on the top of the casing which control the production rate of oil.

Completion: The installation of permanent wellhead equipment for the production of oil and gas.

Compressor station: These station increase the gas's pressure to pump natural gas through pipelines at over significant distances for delivery to markets.

Condensates: Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced and is typically a mixture of pentanes and higher hydrocarbons.

Conventional resources: Discrete accumulations of hydrocarbons contained in rocks with relatively high matrix permeability, which normally have relatively high recovery factors.

Cracker: The cracking of petroleum hydrocarbons, at high temperature in the presence of steam, in order to produce ethylene, propylene and other alkenes. In the Northeast, most of the focus is on ethane as a potential feedstock for the cracking process.

Crude Oil: Liquid petroleum as it comes out of the ground as distinguished from refined oils manufactured out of it.

Cubic foot: A standard unit used to measure quantity of gas (at atmospheric pressure); 1 cubic foot = 0.0283 cubic meters.

Cuttings: Rock chips from the bedrock formation that are cut by the drill bit during borehole drilling and brought to the surface with drilling fluids.

Y

entry

definition

Z

entry

definition

Deviated: Change in the wellbore direction from the path it would naturally take

Directional drilling: The application of special tools and techniques to drill a wellbore at a predetermined angle. Horizontal drilling is a form of directional drilling where the wellbore is ultimately drilled at +/- 90 degrees to the vertical direction.

Drill or Drilling: The using of a rig and crew for deepening and advancing the borehole.

Drilling Mud/Fluid: is used to aid the drilling of boreholes into the earth. A mixture of base substance and additives used to lubricate the drill bit and to counteract the natural pressure of the formation. The three main categories of drilling fluids are water-based muds (which can be dispersed and non-dispersed), non- aqueous muds, usually called oil-based mud, and gaseous drilling fluid, in which a wide range of gases can be used.

Dry Gas: Natural gas composed mainly of methane with only minor amounts of ethane, propane and butane and little or no heavier hydrocarbons in the gasoline range.

Dry hole: A well which has proved to be non-productive.

E&A: Abbreviation for exploration and appraisal.

E&P: Abbreviation for exploration and production.

Enhanced oil recovery (EOR): One or more of a variety of processes that seek to improve recovery of hydrocarbon from a reservoir after the primary production phase.

Environmental assessment: A study that can be required to assess the potential direct, indirect and cumulative environmental impacts of a project.

Estimated ultimate recovery (EUR): The sum of reserves remaining as of a given date and cumulative production as of that date.

Ethane: At standard temperature and pressure, ethane is a colorless, odorless gas. Ethane is isolated on an industrial scale from natural gas, and as a byproduct of petroleum refining. Its chief use is as petrochemical feedstock for ethylene production.

Ethylene: It is a colorless flammable gas. Ethylene is widely used in chemical industry.

Exploration drilling: Drilling carried out to determine whether hydrocarbons are present in a particular area or structure.

Exploration phase: The phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling.

Exploratory well: A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Farm-in: The acquisition of part or all of an oil, natural gas or mineral interest from

a third party. **Farm-out**: The assignment of part or all of an oil, natural gas or mineral

interest to a third party. **FERC**: Federal Energy Regulatory Commission

Field: An area consisting of a single hydrocarbon reservoir or multiple geologically related reservoirs all grouped on or related to the same individual geological structure or stratigraphic condition.

Fishing: Retrieving objects from the borehole, such as a broken drill string, or tools.

Flaring: The burning of natural gas for safety reasons or when there is no way to transport the gas to market or use the gas for other beneficial purposes (such as EOR or reservoir pressure maintenance). The practice of flaring is being steadily reduced as pipelines are completed and in response to environmental concerns.

Flowback water: Water generated initially in conjunction with oil and natural gas exploration and development activities before the well is brought on line for production. This is typically a high percentage of the hydraulic fracturing fluids injected into the well mixed with a relatively low percentage of native formation waters.

Formation pressure: The pressure at the bottom of a well when it is shut in at the wellhead. **Formation water**: Naturally occurring brines (salt water) underlying gas and oil in the formation. **Formation**: A rock layer which has distinct characteristics (e.g. rock type, geologic age).

Fossil fuel: A fuel source (such as oil, condensate, natural gas, natural gas liquids or coal) formed in the earth from plant or animal remains.

Frac Plug: A device placed in the wellbore which is designed to separate the previously fractured zone or stage from the current fracturing operation. Used to separate individual frac stages. There are a variety of types and styles of frac plugs and mechanisms to remove a frac plug.

Frac Stage: An operation where the horizontal wellbore is divided into a number of zones, units or stages for fracturing operations. Stage length may vary but normally ranges from 100-500 feet of horizontal well bore per stage in the Marcellus, Utica and Upper Devonian formations. Frac stages are generally completed from in succession from the toe (furthest point) of the wellbore, moving toward the heel (part of the well closest to the vertical to horizontal curve).

Fracturing fluid: A mixture consisting primarily of water (90-95%), sand or proppant (5-10%), and <1% of additives to optimize the efficiency of the fluids when used for hydraulic fracturing. The additives typically consist of friction reducers, scale inhibitors, biocides, gels, breakers, acids, corrosion inhibitors, and other chemicals dependent on the fracture treatment design.

Fracturing: A method of breaking down a formation by pumping fluid at very high pressures. The objective is to increase production rates from a reservoir.

Fugitive Emissions: Emissions of gases or vapors from pressurized equipment, including pipelines, due to leakage, unintended or irregular releases of gases.

Gas field: A field containing natural gas but no oil.

Gas/oil ratio: The volume of gas at atmospheric pressure produced per unit of oil produced.

Gathering lines: Natural gas pipelines that are generally operated and maintained by an exploration and production company, or their midstream affiliate, to move gas from the well to the custody transfer point. Gathering lines are generally not permitted by the Federal Energy Regulatory Commission or regulated by the Pipeline and Hazardous Material Safety Administration.

GGE: Gallon of Gas Equivalent

Global-warming potential (GWP): The relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide. GWP is calculated over a specific time interval, commonly 100 years. GWP is expressed as a multiple of that for carbon dioxide (whose GWP is standardized to 1).

Commented [SS1]: To refer to as climate change in doc...

GPU: Gas Production Unit

Greenhouse gas (GHG): Atmospheric gases that are transparent to solar (short-wave) radiation but opaque to long-wave (infrared) radiation, thus preventing long-wave radiant energy from leaving Earth's atmosphere. The net effect of these gases is a trapping of absorbed radiation and a tendency to warm the planet's surface. The greenhouse gases most relevant to the oil and gas industry are carbon dioxide, methane and nitrous oxide.

Heavy oil: Crude oil with an API gravity less than 20°. Heavy oil generally does not flow easily due to its elevated viscosity.

Hedging: Making an investment to reduce risk of adverse price movements in an asset.

Held by production: A legal process that allows exploration and production companies to extend the terms of the original lease and pay royalties to the oil and gas rights owner for the life of a producing well.

High BTU Gas/Wet Gas: Any gas with a small amount of liquid present. High BTU gas generally contains attritional hydrocarbons that increase the overall BTU content of the gas stream. Examples of additional hydrocarbons may include propane, butane(s), and ethane(s).

Horizontal drilling: A drilling technique whereby a well is progressively turned from vertical to horizontal so as to allow for greater exposure to an oil or natural gas reservoir. Horizontal laterals can be more than a mile long. In general, longer exposure lengths allow for more oil and natural gas to be recovered from a well and often can reduce the number of wells required to develop a field, thereby minimizing surface disturbance.

Horizontal drilling technology has been extensively used since the 1980s and is appropriate for many, but not all, developments.

Hydraulic fracturing fluids: Mixture of water and proppant along with minor amounts of chemical additives used to hydraulically fracture low permeability formations. Water and sand typically comprise up to 99.5 percent of the mixture.

Hydraulic fracturing: Hydraulic fracturing (also referred to as fraccing, fracking, or hydrofracking or hydrofracturing) is an essential completion technique in use since the 1940s that facilitates production of oil and natural gas trapped in low-permeability reservoir rocks. The process involves pumping fluid at high pressure into the target formation, thereby creating small fractures in the rock that enable hydrocarbons to flow to the wellbore.

Hydrocarbon: A compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate.

Hydrostatic pressure: The pressure which is exerted on a portion of a column of water as a result of the weight of the fluid above it.

Impoundment: A body of water or sludge confined by a dam, dike, floodgate, or other barrier.

Infill wells: Wells drilled into the same reservoir as known producing wells so that oil or natural gas does not have to travel as far through the formation, thereby helping to improve or accelerate recovery.

Injection well: A well used for pumping water or gas into the reservoir. **Inter-State Transmission**: Transmission line crossing state boarders **Intra-State Transmission**: Transmission line within a state

Land Agent/Land Man: Individual who acts as a direct employee or subcontractor on behalf of an exploration and production company to negotiate the terms of an oil, gas, and/or mineral lease agreement.

Lease: A legal document executed between a mineral owner and a company or individual that conveys the right to explore for and develop hydrocarbons and/or other products for a specified period of time over a given area.

LEL: Lower Explosive Limit - Air-gas mixtures will only burn or explode within certain limits, known as the flammable (explosive) limits. (LEL) is the minimum percentage of gas mixed with air that will burn or explode. The LEL for natural gas is 5% (50,000 ppm) gas to 95% air.

Lessee: organization or company interested in

Lessor: An individual of a corporation who has the right to use something of value, gained through a lease agreement with the real owner

Life Cycle Analysis (LCA): LCA is an analytical methodology used to comprehensively quantify and interpret the environmental flows to and from the environment (including air emissions, water effluents, solid waste and the consumption/depletion of energy and other resources) over the life cycle of a product or process.

Liquefied natural gas (LNG): Natural gas that has been converted to a liquid by refrigerating it to -260°F. Liquefying natural gas reduces the fuel's volume by 600 times, enabling it to be shipped economically from distant producing areas to markets.

MBBL: One thousand barrels of crude oil, bitumen, condensate or natural gas liquids.

MBOE: One thousand barrels of oil equivalent.

MCF: One thousand standard cubic feet of natural gas. In the United States, standard conditions are defined as gas at 14.7 psia and 60 degrees F.

MCFe: One thousand standard cubic feet of natural gas "equivalent".

Mechanical Integrity Test (MIT): The act of setting a packer or retrievable bridge plug above the perforations in a wellbore and applying pressure to the annulus in order to ensure soundness of the casing.

Meters

Coriolis Meter: Use the Coriolis effect to measure gas or liquid via an oscillating tube

Orifice Meter: Uses pressure differential of gas or fluid passing through an orifice plate in conjunction with static pressure, fluid density, temperature, pipe size to calculate flow rate

Cone Meters: Uses pressure differential of gas or fluid passing through an orifice plate in conjunction with static pressure, fluid density, temperature, but pipe size may differ from on each side of the meter

Ultrasonic Meter: Use ultrasound to measure flow rates from outside the pipe. Generally used for measuring large volumes.

Methane: A colorless, odorless gas, the simplest paraffin hydrocarbon with a formula of CH4. It is the principal constituent of natural gas and is also found associated with crude oil. Methane is a greenhouse gas in the atmosphere because it absorbs long-wavelength radiation from the Earth's surface.

Method 21: Method 21 is an EPA established procedure used to detect VOC leaks from process equipment using a portable detecting instrument. The instrument detector shall respond to the compounds being processed and be capable of measuring the leak definition concentration specified in the applicable regulation. Detector types that may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

Midstream: Midstream operations generally include the movement, measurement and processing of natural gas from the well to city-gate sales.

Mineral rights: Legal rights that allow for search and removal of minerals on a particular parcel of land.

MMBBL: One million barrels of crude oil, bitumen, condensate or natural gas liquids.

MMBTU: One million British thermal units.

MMCF: One million standard cubic feet of natural gas.

MMCFD: One million cubic feet per day of natural gas.

Natural gas liquids (NGLs): Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Natural gas liquids include natural gas plant liquids (primarily ethane, propane, butane, and isobutane) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).

Natural gas: Naturally occurring hydrocarbon gases found in porous rock formations. Its principal component is usually methane. Nonhydrocarbon gases such as carbon dioxide and hydrogen sulfide can sometimes be present in natural gas.

Naturally occurring radioactive materials (NORM): All radioactive elements found in the environment, including long-lived radioactive elements such as uranium, thorium, and potassium and any of their decay products, such as radium and radon. NORM that has been removed via treatment and concentrated is known as technically-enhanced NORM or TENORM.

Net acres: The percentage that a company owns in an acreage position with multiple owners. For example, a company that has a 50 percent interest in a lease covering 10,000 acres owns 5,000 net acres.

Net Effective Acreage: Used by some companies in stacked play formations. Counts all the layers of rock a company believes they could develop, effectively multiplying the surface acreage by the number of potential formations.

NYMEX: The New York Mercantile Exchange.

O&G: Oil and Gas.

ODNR: Ohio Division of Natural Resources

Odorant: A common constituent of odorants is Ethyl Mercaptan and it is very smelly. The amount of odorant that is added to the gas must be sufficient to make a mixture of one-fifth of the LEL detectable by smell.

Oil field: A geographic area under which an oil reservoir lies.

Oil in place : An estimated measure of the total amount of oil contained in a reservoir, of which only a percentage can be recovered, known as recoverable resources.

Oil: A mixture of liquid hydrocarbons of different molecular weights.

Operator: The company that has legal authority to drill wells and undertake the production of hydrocarbons that are found. The Operator is often part of a consortium and acts on behalf of this consortium.

Optical Gas Imaging: Commercial enterprises have also produced new detection techniques, such as the Optical Gas Imaging (OGI) cameras commercially offered by FLIR and by Opgal beginning in the early 2000's. These handheld cameras make detection possible by display in a screen, allowing visualization of a gas plume that is otherwise invisible to the naked eye. Commercial enterprises have also produced new detection techniques, such as the Optical Gas Imaging (OGI) cameras commercially offered by FLIR and by Opgal beginning in the early 2000's. These handheld cameras make detection possible by display in a screen, allowing visualization of a gas plume that is otherwise invisible to the naked eye.

PADEP: Pennsylvania Department of Environmental Protection

Pay zone: Rock in which oil and gas are found in exploitable quantities.

Permeability: The property of a formation which quantifies the flow of a fluid through the pore spaces and into the wellbore. High permeability means fluid passes through the rock easily

Petroleum: A generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products.

PHMSA: Pipeline and Hazardous Material Safety Administration

PIG (Smart Pig and Dumb Pig): Pipeline Inspection Gauge, performs various maintenance functions in a pipeline including cleaning, segmenting flow, inspection, recording information about the pipeline.

Pipeline: Underground or surface tubing or piping that is installed across states, countries and continents to deliver fuel.

Play: An area in which hydrocarbon accumulations or prospects with similar characteristics occur, such as the Marcellus play in the eastern United States.

Pooling or land pooling: A legal process that allows exploration and production companies to compel unwilling land and mineral rights holders to lease or sell their land and/or mineral rights for exploration, drilling, or pipeline installation if enough of their surrounding neighbors have already agreed. Government agencies require a minimum number of acres of land before granting a well permit; with pooling, companies can collect smaller tracts of land that will accumulate to this total minimum acreage.

Porosity: The percentage of void in a porous rock compared to the solid formation.

Possible reserves: Those reserves which at present cannot be regarded as 'probable' but are estimated to have a significant but less than 50% chance of being technically and economically producible.

Primary recovery: Recovery of oil or gas from a reservoir purely by using the natural pressure in the reservoir to force the oil or gas out.

Probable reserves: Those reserves which are not yet proven but which are estimated to have a better than 50% chance of being technically and economically producible.

Produced water: Water generated from a well in conjunction with oil and natural gas production.

Production well: A well that is capable of producing hydrocarbons in sufficient quantities to justify commercial exploitation.

Propane: a potential constituent of high BTU/wet gas. a colorless, flammable gas occurring in petroleum and natural gas

Proppant: Sand or man-made, sand-sized particles pumped into a formation during a hydraulic fracturing treatment to keep fractures open so that oil and natural gas can flow through the fractures to the wellbore.

Proven field: An oil and/or gas field whose physical extent and estimated reserves have been determined.

Proven reserves: Those reserves which on the available evidence are virtually certain to be technically and economically producible (i.e. having a better than 90% chance of being produced).

RBC: River Basin Commission

Recompletion: The process of entering an existing wellbore and performing work designed to establish production from a new zone.

Recoverable reserves: That proportion of the oil and/gas in a reservoir that can be removed using currently available techniques.

Recovery factor: That proportion of the oil and/gas in a reservoir that can be removed using currently available techniques.

Reserves: Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in production, installed means of delivering oil and gas or related substances to market and all permits and financing required to implement the project.

Reservoir: The underground formation where oil and gas has accumulated. It consists of a porous rock to hold the oil or gas, and a cap rock that prevents its escape.

Resources: Quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources maybe estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations

Rig Down: Disassembling oil and gas field equipment for transportation or storage.

Rig-up: Assembling oil and gas field equipment. To make ready for use.

ROP: Rate of penetration in feet per hour or meters per hour

Roughneck: Drill crew members who work on the derrick floor, threading together the sections of drillpipe when running or pulling a drillstring.

Roustabout: Drill crew members who handle the loading and unloading of equipment and assist in general operations around the rig.

ROW: Right Of Way

Royalty payment: The amount of money exploration and production companies pay to the mineral rights owners of a producing well. Pennsylvania state law requires this rate be no less than 12% of the market price of gas on the day that gas comes out of the ground. Often mineral rights owners have negotiated higher royalties however E&P companies can deduct well production expenses from these royalty payments.

SCADA: Supervisory Control and Data Acquisition, Computer controlled systems that monitor and control industrial processes

Seal formation: The confining rock unit within the carbon dioxide storage assessment unit. The seal formation is a rock unit that suf•ficiently overlies the storage formation and where managed properly has a capillary entrance pressure low enough to effec•tively inhibit the upward buoyant flow of liquids or gases.

Seal: A geologic feature that inhibits the mixing or migration of fluids and gases between adjacent geologic units. A seal is typically a rock unit or a fault; it can be a top seal, inhibiting upward flow of buoyant fluids, or a lateral seal, inhibiting the lateral flow of buoyant fluids.

Secondary recovery: Recovery of oil or gas from a reservoir by artificially maintaining or enhancing the reservoir pressure by injecting gas, water or other substances into the reservoir rock.

Shale gas: Shale gas refers to natural gas that can be generated and trapped within shale units.

Shale oil: Shale oil refers to liquid petroleum that can be generated and trapped within shale units.

Shale: A very fine-grained sedimentary rock that is formed by the consolidation of clay, mud or silt and that usually has a finely stratified or laminated structure. Certain shale formations which are high in organic carbon content, such as the Eagle Ford and the Barnett, contain large amounts of oil and natural gas.

Shut In Well: A well which is capable of producing but is not presently producing. Reasons for a well being shut in may be lack of equipment, market or other.

Source rock: Rocks containing relatively large amounts of organic matter that is transformed into hydrocarbons.

Spacing: The distance between wells producing from the same reservoir, often expressed in terms of acres and is often established by regulatory agencies.

Spud-in: The operation of drilling the first part of a new well.

Surface Location: The location of a well or facility/measurement point.

Surface Reclamation: Restoration of the land surface that had been used for drilling or production which involves regrading and re-vegetating the area.

TCF: One trillion cubic feet of natural gas.

TD: Total depth

Technically recoverable resources : Those resources producible using currently available technology and industry practices. USGS is the only provider of publicly available estimates of undiscovered technically recoverable oil and gas resources.

Tight gas: Natural gas produced from relatively impermeable rock. Getting tight gas out usually requires enhanced technology applications like hydraulic fracturing. The term is generally used for reservoirs other than shale.

Tophole: Vertical portion of the wellbore

Total dissolved solids (TDS): All of the dissolved constituents in water or wastewater, commonly including metals, salts, and other elements or minerals and measured in milligrams per liter (mg/L). Shale energy- derived wastewater (ie flowback and produced water) typically has a high TDS concentration often times greater than seawater's TDS.

Trap: A geologic feature that permits the accumulation and prevents the escape of accumulated fluids (hydrocarbons) or injected carbon dioxide from the reservoir.

TVD: Total vertical Depth

UEL: Upper Explosive Limit - Air-gas mixtures will only burn or explode within certain limits, known as the flammable (explosive) limits. UEL is the maximum percentage of gas mixed with air that will burn or explode. The UEL of natural gas is 14% (140,000 ppm) gas to 86% air

Unconventional reservoirs: Reservoirs with permeability so low (generally less than 0.1 millidarcy) that horizontal hydraulically fractured stimulated wells or other advanced completion techniques must be utilized to extract hydrocarbons at commercial rates. Shale reservoirs such as the Eagle Ford and Marcellus are examples of unconventional reservoirs.

Underground Injection Control (UIC) Well: A type of well used for disposal purposes as regulated under the Safe Drinking Water Act (SDWA) consisting of a steel- and concrete-encased borehole into which waste is injected under pressure. Class II UIC wells handle oil and gas waste for permanent disposal (known as Class II-D wells) or for secondary recovery (known as Class II-R wells). An applicant must demonstrate that the well has no reasonable chance of adversely affecting the quality of an underground source of drinking water before a permit is issued.

Undiscovered: Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included also are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

Unproved reserves: Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved.

Well abandonment: The proper plugging and decommissioning of a well in compliance with all applicable regulations.

Well log: A record of geological formation penetrated during drilling, including technical details of the operation.

Wellbore: The hole drilled by a drilling rig to explore for or develop oil and/or natural gas. Also referred to as a well or borehole.

Wet gas: Produced gas that contains natural gas liquids.

Workover: Remedial work to the equipment within a well, the well pipework, or relating to attempts to increase the rate of flow.

WVDEP: West Virgin

Note to add these erms to glossary:

OMI,

Method 21,

Alternative technologies

Bridge fuel

Fossil fuels

Fugitive emissions

Global warming ·

Global warming potential ·GWP

Greenhouse gases ·

Lifecycle analysis ·LCA

Methane ·

Natural gas ·

Radiative forcing

Shale gas ·

Transitional fuel ·

Unconventional gas

Warming potentials

APPENDIX F ACRONYMS